Paraho

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PARAHO OIL SHALE DEMONSTRATION

COMMERCIAL EVALUATION

FINAL REPORT
VOLUME 5-A.

PARAHO FINAL REPORT

COMMERCIAL EVALUATION

VOLUME 5-A

JULY 30, 1976

PREPARED

by

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for

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FOREWORD

Under a lease approved by the President of the United States in May, 1972, Paraho undertook, in cooperation with the federal government, to demonstrate the engineering, economic and environmental feasibility and desirability of the Paraho processes and hardware for retorting oil shale. This Final Report to participants of the Paraho Oil Shale Demonstration is a six-volume document that describes the research and development operations, the engineering design and cost estimating, and the commercial evaluation studies carried out from late-1973 to mid-1976.

THIS VOLUME 5-A IS CONSIDERED CONFIDENTIAL UNDER THE TERMS OF THE PARTICIPANTS AGREEMENTS WITH PARAHO CORPORATION AND DEVELOPMENT ENGINEERING, INC. MOREOVER, BECAUSE OF THE COMMITMENT TO THE GOVERNMENT NOT TO PUBLISH INFORMATION PREMATURELY, DISTRIBUTION SHOULD BE STRICTLY CONTROLLED ON A NEED-TO-KNOW BASIS UNTIL AFTER THIS MATERIAL HAS BEEN PUBLISHED BY THE GOVERNMENT OR PARAHO.

The field operations were conducted at the Anvil Points Oil Shale Research Facilities located on the Naval Oil Shale Reserves near Rifle, Colorado. Administration of these leased facilities was transferred from the Bureau of Mines (BOM) to the Energy Research and Development Administration (ERDA) when the latter agency was formed in 1974.

The Paraho Oil Shale Demonstration was privately sponsored by the following seventeen participants at a total cost of $9.4 million:

Sohio Petroleum Company
Southern California Edison Company
The Cleveland-Cliffs Iron Company
Gulf Oil Corporation

Arthur G. McKee and Company
Kerr-McGee Corporation
Shell Development Corporation
Standard Oil Company (Indiana)
The Carter Oil Company (Exxon)
Mobil Research and Development Corporation
Webb-Gary-Chambers-McLoraine (Group)
Sun Oil Company
Texaco Inc.
Phillips Petroleum Company
Atlantic Richfield Company
Marathon Oil Company
Chevron Research Company

These participants received the right to license Paraho's oil shale technology on favorable terms for their support and cooperation which are gratefully acknowledged.

The results of Paraho's operations at Anvil Points are encouraging. They demonstrate that the process works, that the equipment is operable and durable, that thermal efficiencies and yields are high, and that the entire system developed is environmentally acceptable. The extended periods of Paraho retort operations and the results obtained demonstrate this. The evidence includes the 77-day Pilot Plant run and the 56-day Semi-Works run, both of which were terminated voluntarily.

After the 56-day retort run, 10,000 barrels of Paraho crude shale oil were shipped to the nearby Gary Western Refinery and converted into military products. This federally funded work was done for the U.S. Navy's Energy and Natural Resources Research and Development Office. That Office coordinated the refining and the nationwide, refined product testing program and publishing a report entitled:

Production and Refining of 10,000 Bbl. Paraho Crude Shale Oil Into Military Fuels, U. S. Navy Contract #N0014-75-C-0055

A retorted shale management research project jointly funded by the Bureau of Mines and Paraho will be completed in late-1976 at an estimated additional cost of $0.5 million. At that time, a report entitled, "Retorted Shale Management", will be issued as the concluding volume of this report.

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CONTENTS

VOLUME 5-A

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SECTION 1

EXECUTIVE SUMMARY

The objective of this report is to provide information to the management of the participating companies regarding the commercial feasibility of an oil shale venture.

Numerous alternates have been studied. All are energy self-sufficient. Two are summarized here. One produces pipelineable crude shale oil. The other upgrades the crude shale oil to a high quality syncrude. In all cases, the total oil shale retorted and the gross crude shale oil produced remain constant at 157,400 tons per stream day and 100,000 barrels per stream day, respectively. The amount of net products vary according to the methods of processing and upgrading and the internal fuel requirements. All costs necessary to provide a proper plant site, a complete mine and plant, and onsite and offsite plant facilities have been included. The results are summarized as follows:

	Crude Shale Oil Case	Syncrude Oil Case
Feed		
Oil Shale TPSD	157,400	157,400
Water - Acre ft./yr.	5,740	8,310
Net Products		
Crude Shale Oil BPSD	99,170	--
Syncrude BPSD	--	88,542
Sulfur TPSD	85	191
Ammonia TPSD	43	415
Excess Power Generated MW	53	--
Economics (1976 Dollars)		
Investment - $ Billions	1.2	1.6
Operating Cost - $ Millions/Yr.	150	190
Oil Price (100% Equity Basis):		
15% Return on Investment $/Bbl.	11.50 (1)	17.50 (1)

(1) These prices should not be directly compared to crude oil prices. See Pg. 1-2.

This preliminary Commercial Evaluation Study indicates the following:

- A crude shale oil price of $11.50 per barrel is needed to yield a 15% return on investment. The prices of crude shale oil and conventional crude oil cannot be properly compared without examining the possible added refinery investment and operating costs related to the processing of crude shale oil. To refine imported Saudi Light or African Sweet crudes (which in July, 1976 delivered to the U. S. Gulf Coast at $13 to $14 per barrel) requires lower refining investment than crude shale oil.

- A syncrude price of $17.50 per barrel is needed to yield a 15% return on investment. Syncrude is a high quality "bottomless" material that should carry a premium value over imported crudes. This is because of the higher proportion of high priced products available from syncrude, the additional advantage syncrude offers refiners having "bottom of the barrel" limitations, and the possibility that syncrude might be marketable directly as a wide-range distillate fuel.

- Shale oil and imported crude oil are exempt from domestic price control. However, until a free market in domestic oil is reestablished, the true penalty and premium values of crude shale oil and syncrude will not be known. This information is essential before pioneer plant commitments can be made. A pioneer plant yield of less than 15% rate of return on investment is inadequate to justify building a commercial plant with the uncertainties described below.

- If the world price of crude oil escalates faster than the investment required to build shale plants, or if, in the best interest of the United States, our dependence on imported crude should be limited by restricting imports, crude shale oil and syncrude could command the prices required to become a viable energy supply.

- A commercial oil shale installation will consist of very large and complex units of mining, retorting, and upgrading - all close coupled and interdependent. A high operational risk is involved since each operating unit must have a high "on-stream" factor to maintain the desired production levels. Failure to achieve this reliability would have a major impact on project economics. In addition, such investments are vulnerable to technological, political, commercial, and environmental risks that must be resolved. Consequently, as a first and an important step, the program that has been proposed by Paraho should be implemented to demonstrate this technology, at full-scale, in a module of the size and design anticipated for commercial plants. Such a demonstration will provide a sound basis for:

    - Establishing reliability and "on-stream" factor.

    - Predicting capital and operating costs for commercial units more accurately.

    - Evaluating environmental impact, such as retorted shale disposal and ambient air quality. Since much of the undeveloped oil shale country, in its natural state, is believed to be in violation of the Clean Air Act standards, some changes in these will be needed.

- Determining minimum water requirements - an important aspect of oil shale development.

Such a module will represent a large research investment with no immediate return. Therefore, to maintain the momentum established by Paraho, encouragement of this step by joint government industry cooperation is essential.

2. INTRODUCTION

Paraho

SECTION 2

INTRODUCTION AND OBJECTIVE

This commercial evaluation for an oil shale venture based on Paraho retorts is contained in two volumes. This volume, 5-A is a summary. Volume 5-B, which is Proprietary and Secret, contains the details.

Economic analysis of various aspects of the Paraho retorting process has been a continuing effort throughout the project. A preliminary commercial economical analysis was presented in May, 1975, in the "Prospectus for a Paraho Full-Size Module" brochure.

The objective of this report is to provide information to the participating companies regarding the commercial feasibility of an oil shale venture. The objectives, specifications, and contents of this report were developed by joint discussions between the Technical Advisory Committee of participants, The Cleveland-Cliffs Iron Company, Arthur G. McKee & Company, Sohio Petroleum Company, and Paraho.

This commercial feasibility study includes facilities for:

- Mining, crushing, screening, materials handling, and retorted shale disposal.
- Direct and indirect heated retorting (Combination heating is not included due to insufficient data).
- Upgrading of shale oil to a pipelineable product.
- Upgrading of gases to an environmentally acceptable quality.

o Utilities and offsites.

o Waste treatment.

This report provides facilities planning and an order-of-magnitude estimate of $\pm 25\%$ accuracy. Economics are worked out using a standard discounted cash flow method on 100% equity basis.

In order to make this report more realistic and representative, it was felt necessary to select a specific site rather than a hypothetical location. The site selection on U.S. Naval Oil Shale Reserve No. 1 is considered to be typical for an oil shale venture, and oil shale for the Paraho Oil Shale Demonstration was extracted from the same area. However, this does not represent an endorsement by the Department of Navy or any other government agency.

3. KEY RESULTS

4. DESIGN BASIS

SECTION 3
KEY RESULTS

A total of five cases have been studied. In all cases the total oil shale to be retorted remains constant - 157,421 tons per stream day, as does the crude shale oil produced at the retort outlet - 100,000 barrels per stream day. The amount of products produced vary according to the processing plan used in each case. While some changes could occur in the retorted shale management area, for the purposes of this study, all cases are assumed to require the same capital and operating costs for mining, material handling, and retorted shale management. The necessary work and related costs to provide a proper site, infrastructure, and onsite and offsite facilities have been included for all cases. Both capital and operating costs have been varied as changes are made in the retorting and upgrading facilities.

3.1 DESCRIPTION OF CASES

In all cases oil shale is mined and retorted to produce a crude shale oil.

3.1.1 Base Case

Coking of crude shale oil with hydrotreating of coker liquid products is used. The major liquid product is a low nitrogen, low sulfur, low pour point syncrude.

Twelve Direct Heated and twelve Indirect Heated Paraho retorts were selected to provide an essentially balanced energy system. Hydrogenation of the individual naphtha, light gas oil and heavy gas oil liquid products produces a syncrude product. The coke produced in the refining step is burned in a power plant (built and operated by others).

3.1.2 Alternate 1

Direct hydrogenation of crude shale oil is used. Again, the major liquid produced is a low nitrogen, low sulfur, low pour point syncrude.

This case requires 18 Direct Heated and 6 Indirect Heated Paraho retorts to balance the fuel production and requirements.

3.1.3 Alternate 2

No upgrading of crude shale oil is carried out. Three retorting schemes are considered.

- 2A Paraho Direct Heated retorts only
- 2B Paraho Indirect Heated retorts only
- 2C A combination of Paraho Direct Heated and Indirect Heated retorts

3.1.4 Alternate 2A

A total of 24 Direct Heated Paraho retorts are used.

Crude shale oil, with a pour point depressant is pipelined from the complex.

A large amount of low Btu gas is produced in this case. The gas is cleaned and used to generate electrical power and the excess power is exported through a high voltage power grid.

3.1.5 Alternate 2B

A total of 24 Indirect Heated Paraho retorts are used.

Crude shale oil, with a pour point depressant is pipelined from the complex.

The fuel for the IH retort heaters requires that the high Btu gas (after cleaning) from the retorts be supplemented with liquid fuel. The net liquid product output reflects this demand; a cost of producing liquid fuel that is environmentally acceptable is also included in the operating costs.

3.1.6 Alternate 2C

Retorting utilizes a combination of Paraho retorts - 18 Direct Heated and 6 Indirect Heated with a fuel pool balanced to produce no excess low Btu gas.

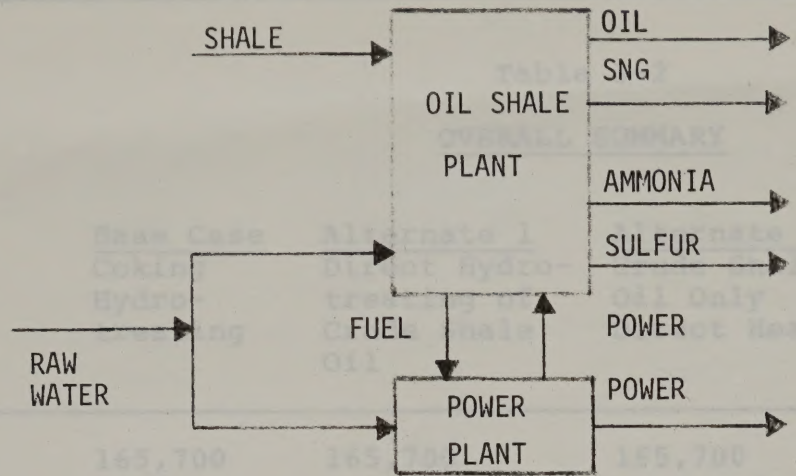
The major product is crude shale oil. A pour point depressant is added so that the product can be handled through conventional pipelines. A quantity of SNG is produced and exported as a pipeline gas product. The fuel balance is such that an excess of Indirect Heated retort gases are produced. A SNG plant is included in the capital and operating costs values; this plant is required to treat the Indirect Heated retort gases so that they meet existing natural gas pipeline specifications.

The full scale project facilities for each of the five case studies are described in the following Section 4 including:

- o Mining and materials handling
- o Paraho retorting
- o Retorted shale disposal
- o Upgrading of shale oil and gases
- o Offsites and support facilities

Key results of the evaluation for each of the cases are presented in Table 3-1, Feed and Product Summary, and Table 3-2, Overall Summary.

TABLE 3-1
FEED AND PRODUCT
SUMMARY



	BASE CASE	ALTERNATE 1	ALTERNATE 2A	ALTERNATE 2B	ALTERNATE 2C
FEEDS					
SHALE, TPSD	157,421	157,421	157,421	157,421	157,421
RAW WATER, ACRE FT./YR.	8,070	8,310	5,740	3,460	5,130
PRODUCTS					
CRUDE SHALE OIL, BPSD	--	--	99,170	83,560	94,220
HYDROTREATED OIL, BPSD	81,265	88,542	--	--	--
SNG, MMSCFD	--	--	--	--	16.4
AMMONIA, TPSD	317	415	43	23	38
SULFUR, TPSD	193	191	85	114	92
FUEL (TO POWER PLANT), BPSD, FOE	17,409	18,330	18,531	13,475	15,104
POWER (TO OIL SHALE PLANT), Kw.	343,000	344,700	277,500	269,500	279,500
POWER (TO GRID), Kw.	--	--	53,500	--	--

Table 3-2

OVERALL SUMMARY

	Base Case Coking Hydro-treating	Alternate 1 Direct Hydro-treating of Crude Shale Oil	Alternate 2A Crude Shale Oil Only Direct Heated	Alternate 2B Crude Shale Oil Only Indirect Heated	Alternate 2C Crude Shale Oil Only Direct Heated & Indirect Heated
Mining Rate TPSD	165,700	165,700	165,700	165,700	165,700
No. of Direct Heated Retorts	12	18	24	---	18
No. of Indirect Heated Retorts	12	6	---	24	6
Retort Production:					
Crude Shale Oil (BPSD)	100,000	100,000	100,000	100,000	100,000
Gas:* D.H. (FOE BPSD)	12,424	18,636	24,849	---	18,636
(MMSCFSD)	(482.8)	(724)	(966)	---	(724)
I.H. (FOE BPSD)	5,678	2,839	---	11,355	2,839
(MMSCFSD)	(39.0)	(19.5)	---	(78)	(19.5)
Condensate (BPSD)	400	200	---	800	200
Net Production:					
Synthetic Crude (BPSD)	81,265	88,542	---	---	---
Crude Shale Oil (BPSD)	---	---	99,170	83,560	94,220
SNG (MSCFD)	---	---	---	---	16.4
Total Facilities Investment $Millions	1,619	1,578	1,166	1,285	1,216
Total Facilities Operating Cost $Millions/Year	195	191	148	179	162
Synthetic Crude Price at 15% ROI 100% Equity	19.35	17.50	11.50	15.75	12.70

* Net gas after cleaning

3.2 ECONOMIC ANALYSIS

An economic analysis was developed for a 100,000 BPSD crude shale oil complex. The capital investment and operating cost requirement were developed for a 165,700 ton per day mining operation, retorting facilities to produce 100,000 barrels per stream day of crude shale oil and upgrading facilities.

The investment and operating costs for cases studied are summarized on the following Tables 3-3, Investment Summary and 3-4, Operating Cost Summary.

Table 3-3

INVESTMENT SUMMARY - $MILLIONS

	Base Case Coking Hydro-treating	Alternate 1 Direct Hydro-treating of Crude Shale Oil	Alternate 2A Crude Shale Oil Only Direct Heated	Alternate 2B Crude Shale Oil Only Indirect Heated	Alternate 2C Crude Shale Oil Only Direct Heated & Indirect Heated
Mining	265	265	265	265	265
Materials Handling (Crushing, Screening, etc.)	147	147	147	147	147
Retorting	391	346	302	480	346
Retort Gas Cleaning & Upgrading	60	80	90	25	91
Crude Shale Oil Upgrading	270	262	---	---	---
Retorted Shale Management	53	53	53	53	53
Water Supply	18	18	15	13	14
Offsites	162	150	100	94	97
Site Prep & Roads	30	30	27	27	27
SUBTOTAL	1,396	1,351	999	1,104	1,040
OTHER COSTS:					
Reserve Acquisition	20	20	20	20	20
Owner Engrg. & Proj. Management	20	17	12	13	12
Organization Develop & Training	30	30	25	25	25
Startup & Fix-its	60	58	40	53	49
Environmental Monitoring	10	10	10	10	10
Catalysts & Chemicals	8	18	1	1	1
Royalties - Prepaid	5	4	1	1	1
Working Capital	60	60	50	50	50
Other	10	10	8	8	8
SUBTOTAL	223	227	167	181	176
TOTAL	1,619	1,578	1,166	1,285	1,216

Table 3-4

Base Case & Alternates
Annual Operating Costs
($ Millions/Yr)

	Base Case	Alternate 1	Alternate 2A	Alternate 2B	Alternate 2C
Mining, Crush, Retorted Shale	77.22	77.22	77.22	77.22	77.22
Retort, & Retort Gas	69.36	64.12	64.83	74.17	68.52
Upgrading & Offsites	38.80	41.11	6.32	6.15	6.24
Water Supply	2.15	2.19	1.70	1.37	1.66
Administration	1.78	1.77	1.17	1.17	1.21
FOE (Credit)	(21.62)	(24.57)	(23.01)	(23.37)	(19.95)
Fuel Oil (Debit)	-	-	1.11	21.60	7.60
Insurance & Tax	23.80	22.56	15.60	17.68	16.40
Corporate Overhead	4.00	4.00	3.20	3.20	3.40
TOTAL	195.49	191.40	148.14	179.20	162.30

3.3 ECONOMIC ASSUMPTIONS

Project Schedule	24 project years 5 design-construct years 21 production years (1 @ 12.5%, 1 @ 56.25%, 19 @ full) See Figure 3-1
First half 1976 dollars	No change in dollar value during the project
Owner's Equity	100%
Service Factor	90%
Investors rate of return	15%
Depletion allowance on value of retorts liquid yield	15%
Depreciation	Mining 10 years Retorting & Processing 15 years Water Supply 20 years
Investment Credit	7% on initial capital
Income tax rate	51% (Federal plus State)
Severance Tax	0%
Insurance and other taxes	2% of initial capital (Site Prep. excluded)
Extraction royalty	11¢ per ton of mined shale (29 gal./ton)
Retort royalty	10¢ per bbl. crude shale oil
Process royalty	Varies - typical for process unit included
Project Economics	Plant gate basis
By-product Values	Ammonia - $140/ton Sulfur - zero value SNG - $1.50/MM Btu

Water is available from Colorado River in required volume and at $25 per acre-foot.

Plant effluents will meet Federal/Colorado environmental requirements.

A permanent highway will be constructed by the state from Rio Blanco to the plant site.

Associated community development will be by others.

No extraordinary taxes or assessments are included.

Exploration and environmental studies - $10 MM

Project abandonment costs - zero.

Salvage value at termination - zero.

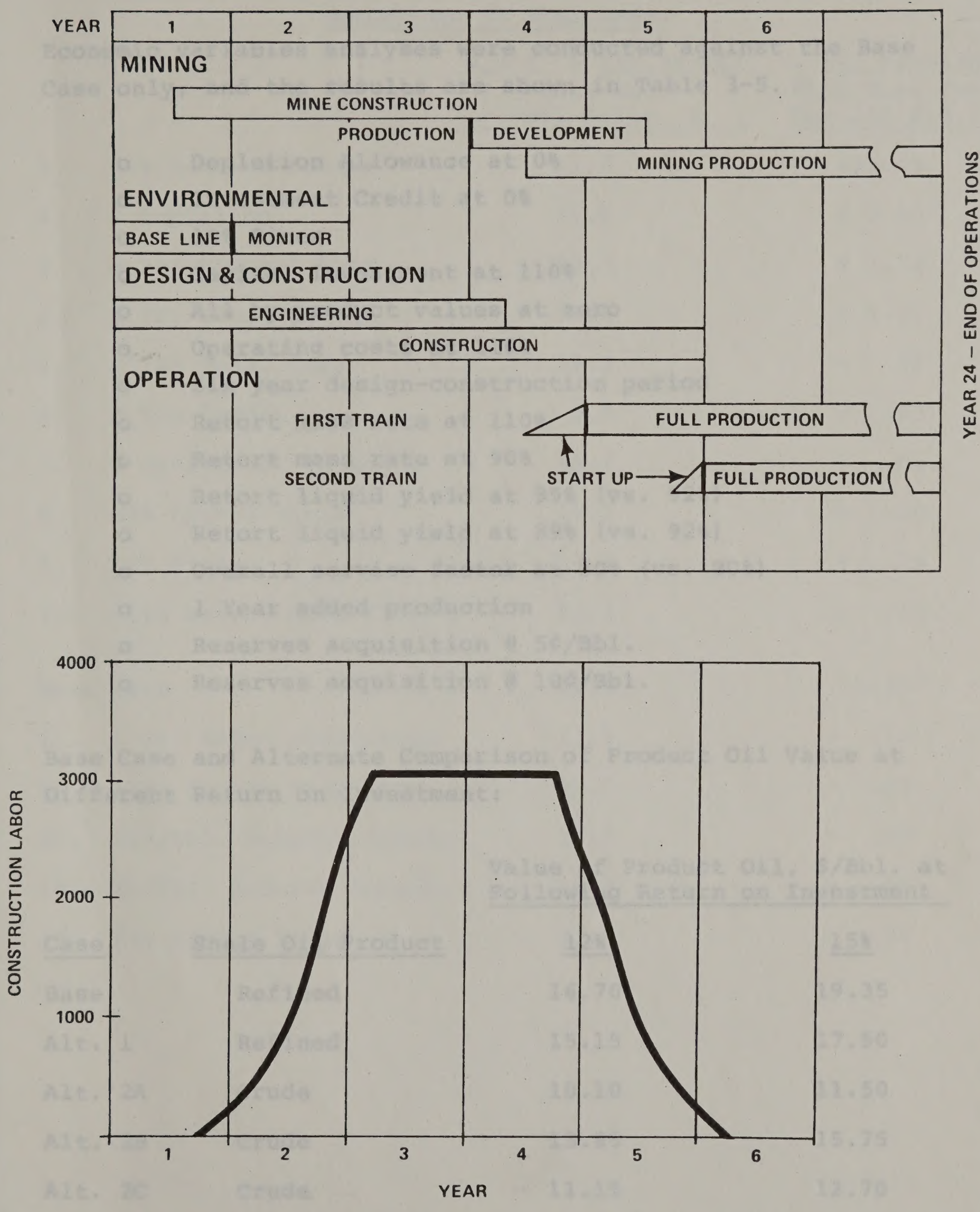
Electric power - purchased at 2.2¢/KWH.

Fuel to external power plant - value equivalent to 2.2¢/KWH power.

Addition of pour point depressant in crude shale oil cases 2A, 2B, and 2C will cost 25¢/barrel. This is based on laboratory tests of commercially available pour point depressants in reducing crude shale oil pour point to 40°F.

Figure 3-1

PROJECT SCHEDULE – BASE CASE



CONSTRUCTION MANPOWER

3.4 VARIABLE STUDIES

Economic variables analyses were conducted against the Base Case only, and the results are shown in Table 3-5.

- Depletion Allowance at 0%
- Investment Credit at 0%
- 10% Fines
- Capital Investment at 110%
- All by-product values at zero
- Operating costs at 110%
- Six year design-construction period
- Retort mass rate at 110%
- Retort mass rate at 90%
- Retort liquid yield at 95% (vs. 92%)
- Retort liquid yield at 89% (vs. 92%)
- Overall service factor at 80% (vs. 90%)
- 1 Year added production
- Reserves acquisition @ 5¢/Bbl.
- Reserves acquisition @ 10¢/Bbl.

Base Case and Alternate Comparison of Product Oil Value at Different Return on Investment:

		Value of Product Oil, $/Bbl. at Following Return on Investment	
Case	Shale Oil Product	12%	15%
Base	Refined	16.70	19.35
Alt. 1	Refined	15.15	17.50
Alt. 2A	Crude	10.10	11.50
Alt. 2B	Crude	13.85	15.75
Alt. 2C	Crude	11.15	12.70

Table 3-5

VARIATIONS TO BASE CASE

		R.O.I. @ $18.00/Bbl. Plant Gate Oil Price, %	± Oil Price/Bbl. From Base Case For 15% R.O.I.
1.	80% Service factor	11.0	+$2.45
2.	0 Depletion	11.5	+ 2.15
3.	+ 10% Capital Cost	12.5	+ 1.15
4.	6 Yr. Construction	12.6	+ 1.15
5.	+ 10% Oper. Cost	12.7	+ .65
6.	0 Tax Credit	12.9	+ .65
7.	0 By-Product Values	12.9	+ .55
8.	89% Liquid Yield	13.2	+ .30
9.	10% Fines	13.2	+ .25
10.	-10% Retort Mass Flow	13.4	+ .15
Base Case		13.5	19.35*
11.	1 Yr. Added Production	13.7	- .10
12.	+10% Retort Mass Flow	13.7	- .15
13.	10¢/Bbl. Reserve Acquis.	13.7	- .20
14.	5¢/Bbl. Reserve Acquis.	13.7	- .25
15.	95% Liquid Yield	13.9	- .35

*Oil price for base case at 15% R.O.I.

4. DESIGN BASIS

SECTION 4

DESIGN BASIS AND PROJECT DESCRIPTION

4.1 SITE DESCRIPTION

4.1.1 General

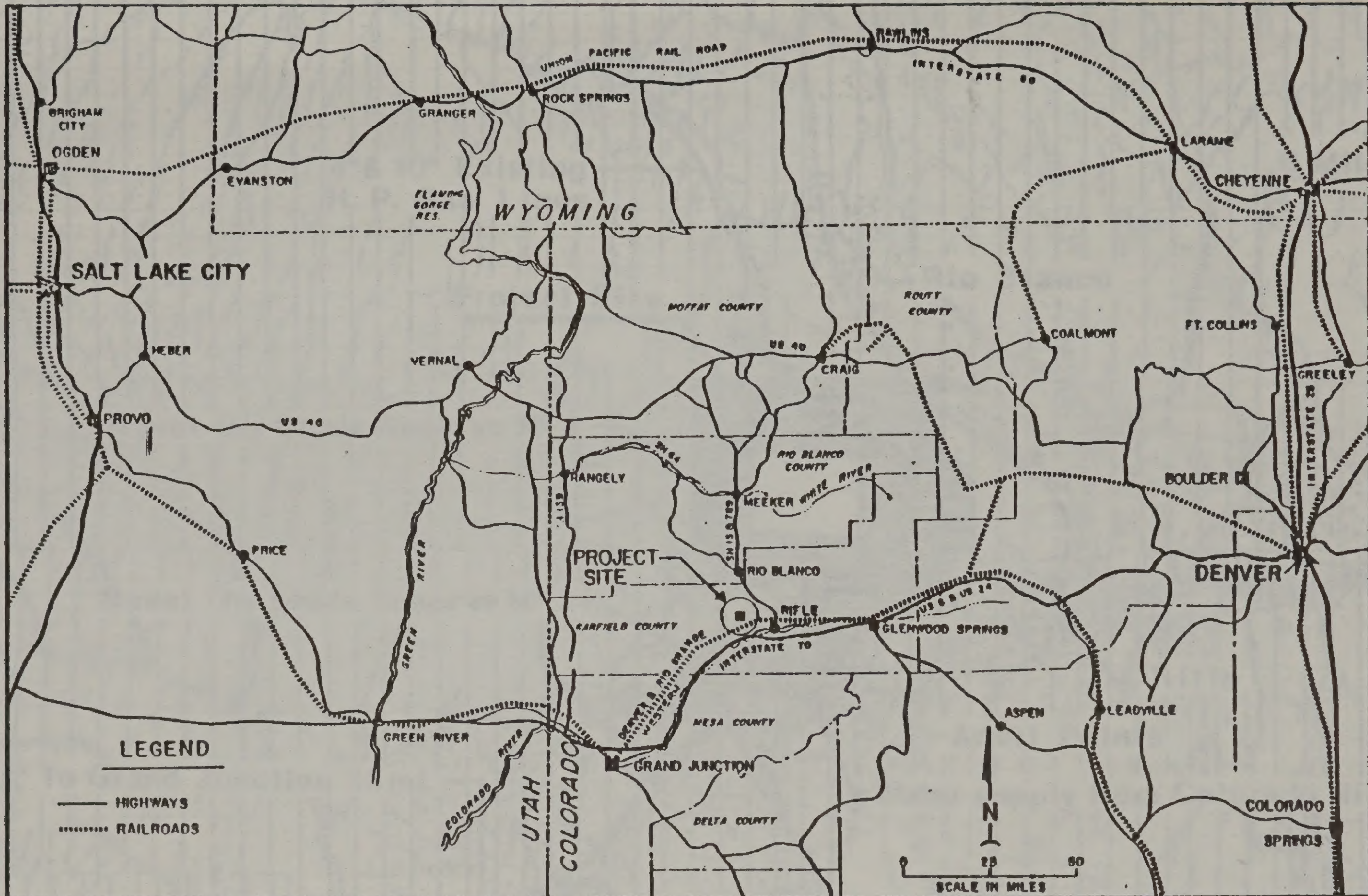
The site assumed for this study is located within Garfield County in northwest Colorado. The plant site, including the area to be mined covers 12 square miles in the Naval Oil Shale Reserve No. 1 on the Roan Plateau. It is approximately three miles north of the site of the Paraho Oil Shale Demonstration at Anvil Points, Colorado. Figures 4-1 and 4-2 indicate the site.

The site topography and overall project layout are shown in Figure 4-3. The site is hilly containing light woods and brush with surface elevations varying from 8000 feet to 9160 feet. Drainage from the site presents no problems and eventually flows to the Colorado River. Bearing capacity of the soil is in excess of 3000 lbs. per square foot.

Access to the site is currently by unimproved dirt road from a main highway running from Rifle to Rio Blanco which, in turn, connects with other major highway arteries. The nearest railroad connection is in Rifle where provision for a siding will be made. Rail service to the site will not be provided. The nearest commercial airport is at Grand Junction.

4.1.2 Plant Layout

The mined area and layout is shown in Figure 4-3. Mine shafts are located at the centroid of the projected mining area. The mine shafts extend 1055 feet to the mine floor

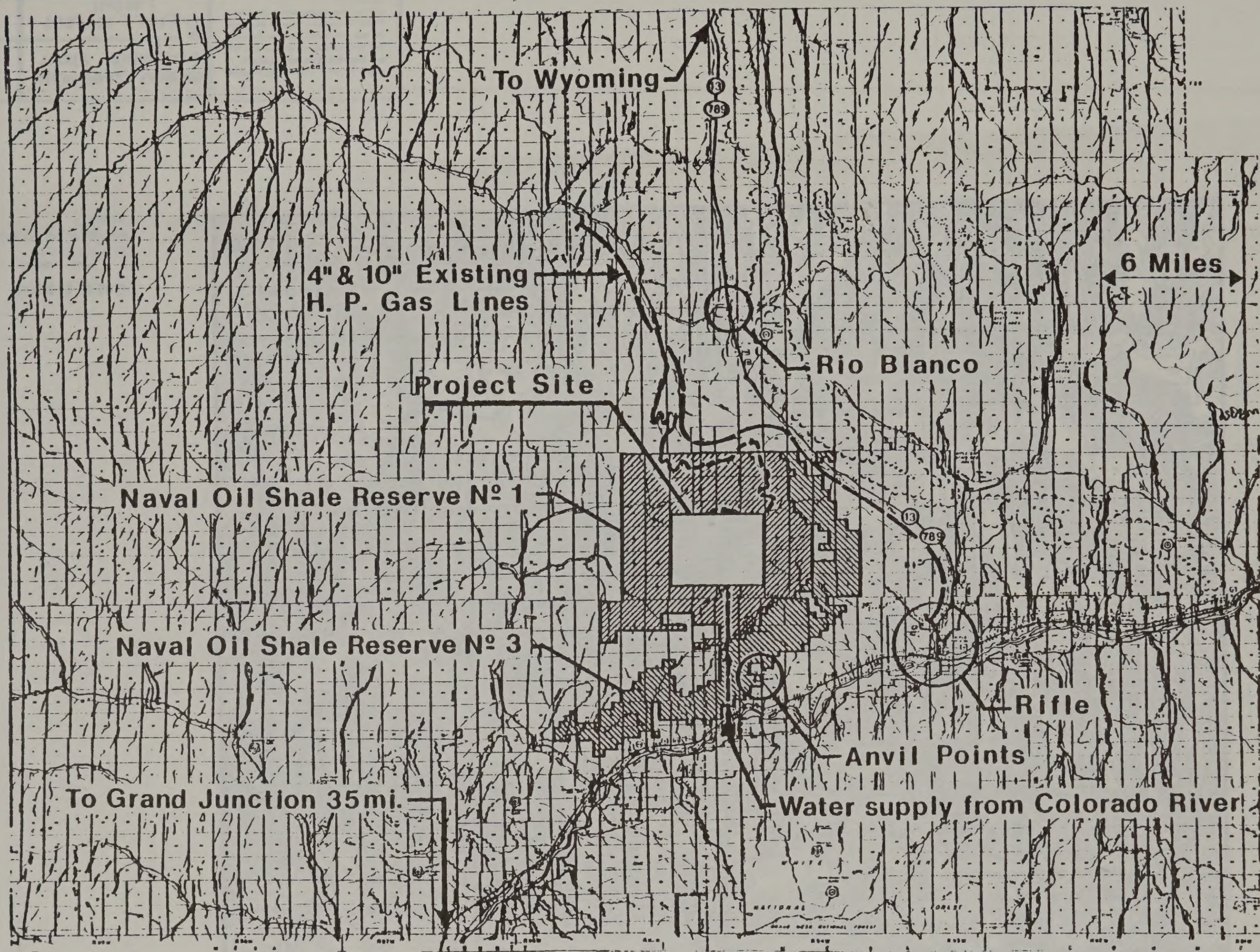


PARAHO COMMERCIAL EVALUATION STUDY

REGIONAL MAP

McKee
ENGINEERS AND CONSTRUCTORS
CLEVELAND, OHIO

FIG. 4-1

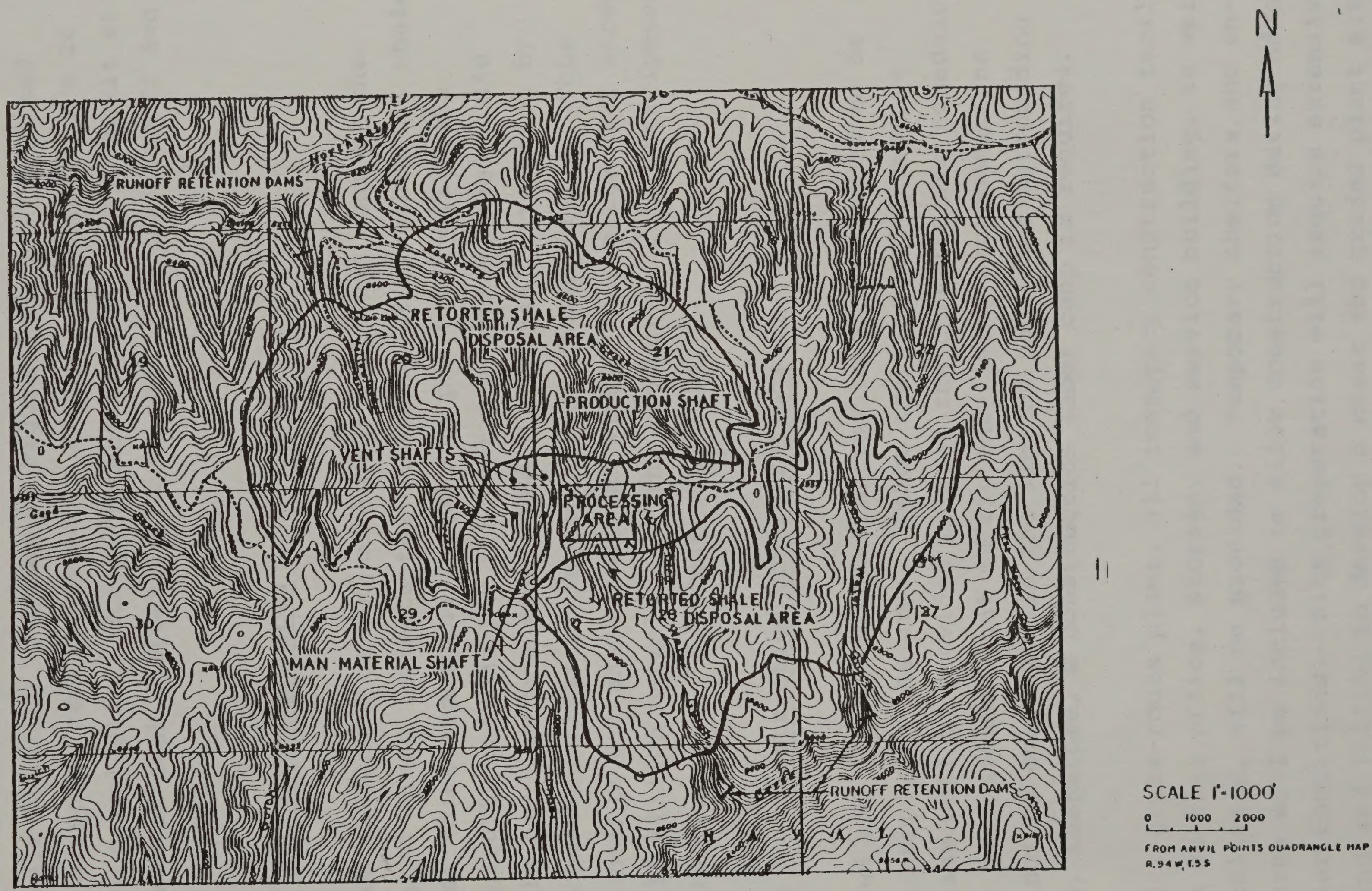


PARAHO COMMERCIAL EVALUATION STUDY

AREA MAP

McKee
ENGINEERS AND CONSTRUCTORS
CLEVELAND, OHIO

FIG. 4-2



PARAHO COMMERCIAL EVALUATION STUDY

OVERALL PROJECT LAYOUT

McKee
ENGINEERS AND CONSTRUCTORS
CLEVELAND, OHIO

FIG. 4-3

The processing area is situated such that the mine shafts are in close proximity, but dust intake from the processing area is minimal. The processing area plan, which includes the crushers, screening, retort batteries, and associated materials handling is shown in Figure 4-4. The retorted shale disposal area outlined in Figure 4-3 represents a 20 year disposal pile. Runoff retention dams will be built at the base on each disposal area to collect normal runoff and leach waters.

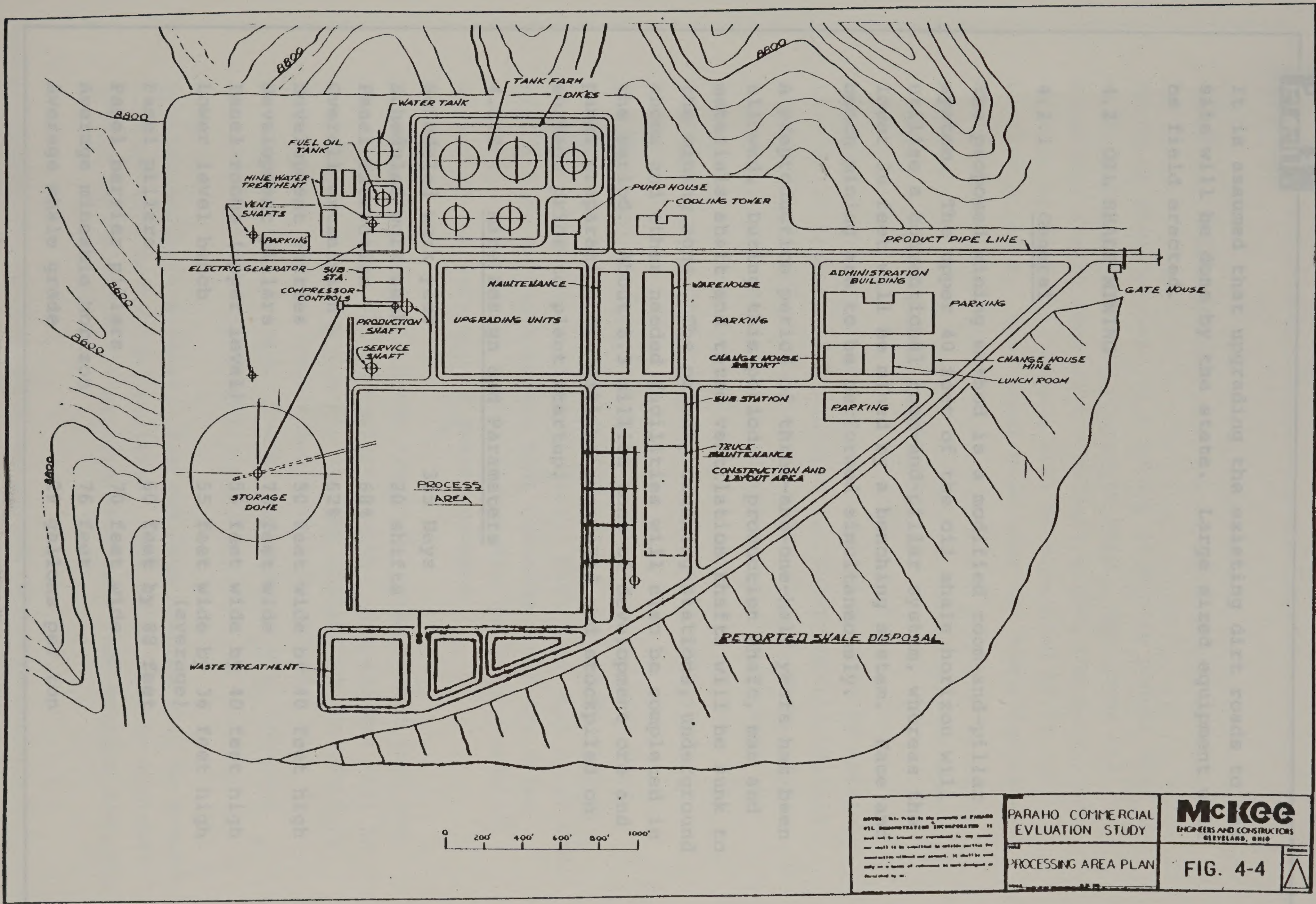
4.1.3 Site Resources

Assayed samples from two core hole drillings done by the Bureau of Mines indicate the existence of mineable oil shale 76 feet thick averaging 29 gallons per ton. Oil shale averaging 29 gallons per ton contains approximately 2040 barrels per acrefoot mined, and the overall extraction by the room-and-pillar mining technique chosen is 62%. Thus the mineable oil shale reserves within the entire 7680 acres are 738 million barrels. At the production rate anticipated, this represents a 19.7 year mine life.

4.1.4 Construction Considerations

Skilled and unskilled construction labor is assumed to be short supply in the area. Labor training and incentive programs will be provided to meet the construction schedule. It is also assumed that sufficient living accommodations will not be available in the limited populated surrounding areas, therefore, a construction labor camp is required.

Being a grass-roots plant, all temporary construction facilities such as office, storage, and service building, as well as utilities, will be provided. Temporary shelters and enclosures will be included to allow construction during adverse weather conditions. Site preparation will require extensive cutting and filling to develop a clear and graded plant site.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TANK FARM
DIKES
WATER TANK
FUEL OIL TANK
MINE WATER TREATMENT
VENT SHAFTS
PARKING
PUMP HOUSE
COOLING TOWER
PRODUCT PIPE LINE
ELECTRIC GENERATOR
SUB STA.
COMPRESSOR CONTROLS
PRODUCTION SHAFT
SERVICE SHAFT
MAINTENANCE
UPGRADING UNITS
WAREHOUSE
PARKING
ADMINISTRATION BUILDING
PARKING
GATE HOUSE
CHANGE HOUSE RETORT
CHANGE HOUSE MINE
LUNCH ROOM
SUB STATION
PARKING
TRUCK MAINTENANCE
CONSTRUCTION AND LAYOUT AREA
PROCESS AREA
STORAGE DOME
RETORTED SHALE DISPOSAL
WASTE TREATMENT
0 200' 400' 600' 800' 1000'
PARAHO COMMERCIAL EVLUATION STUDY
PROCESSING AREA PLAN
McKee
ENGINEERS AND CONSTRUCTORS
CLEVELAND, OHIO
FIG. 4-4

It is assumed that upgrading the existing dirt roads to the site will be done by the state. Large sized equipment will be field erected.

4.2 OIL SHALE MINING

4.2.1 General

The proposed mining method is a modified room-and-pillar system. The upper 40 feet of the oil shale horizon will utilize a conventional room-and-pillar system, whereas the lower 36 feet will be mined by a benching system. Face and bench mining are to be performed simultaneously.

A preproduction period of three-and-one-half years has been allowed. During this period, a production shaft, man and materials shaft and three ventilation shafts will be sunk to the mining zone. The primary crushing stations, underground shops and other needed facilities will also be completed in the period. About 8.3 million tons of development ore and panel preparation ore will be excavated and stockpiled on surface prior to plant startup.

4.2.2 Mine Design and Parameters

Scheduled work year	355 Days
Scheduled work week	20 shifts
Panel extraction	68%
Overall extraction	62%
Development entries	50 feet wide by 40 feet high
Development pillars	70 feet wide
Panel rooms (upper level)	55 feet wide by 40 feet high
Lower level bench	55 feet wide by 36 feet high (average)
Panel pillars	60 feet by 88 feet
Panel barrier pillars	70 feet wide
Average mineable horizon	76 feet
Average shale grade	29 gallons per ton

4.2.3 Mining Layout

The mine plan consists of a series of mining panels that are eight rooms wide and 16 crosscuts deep. The rooms and crosscuts are 55 feet wide. Pillars within the panels are 60 feet by 88 feet. Panels will be separated by 70 foot barrier pillars. Each panel will have two ramps for access to the lower level.

4.2.4 Mining Function Description

Drilling. The upper level drilling will be done by specialized drill jumbos, each mounting two rotary drills capable of drilling 4-1/4 inch diameter holes 27 feet deep. The units are to be self-contained with an air compressor and drill water tank. Lower level drilling will be done with vertical rotary drills which are also self-contained.

Charging and Blasting. Ammonium nitrate mixed with fuel oil will be the primary blasting agent. The AN/FO will be placed in blastholes pneumatically. Each hole will be primed with a high strength primer that contains a cap and delay element. The overall powder factor will be 0.51 pounds of explosive for each ton of shale produced.

Loading and Hauling. Large front-end loaders will load the blasted ore into 75 ton haulage trucks. Haulageways will be assigned for one way travel, thereby minimizing interference and delays. Loader requirements will be constant once full production is attained. Truck requirements will increase as haul distances increase.

Scaling and Roof Bolting. Rib and face scaling will be accomplished with mechanical scalers. Roof bolts will be systematically installed in all exposed back by a roof bolting machine.

Primary Crushing and Hoisting. Toothed single roll crushers, 48 inch by 72 inch, will be used to crush shale to minus 12 inch prior to hoisting. Total mine production will be hoisted from a single 38 foot diameter shaft with four 100 ton skips. Primary crushers will be located underground.

4.3 RETORT FEED PREPARATION

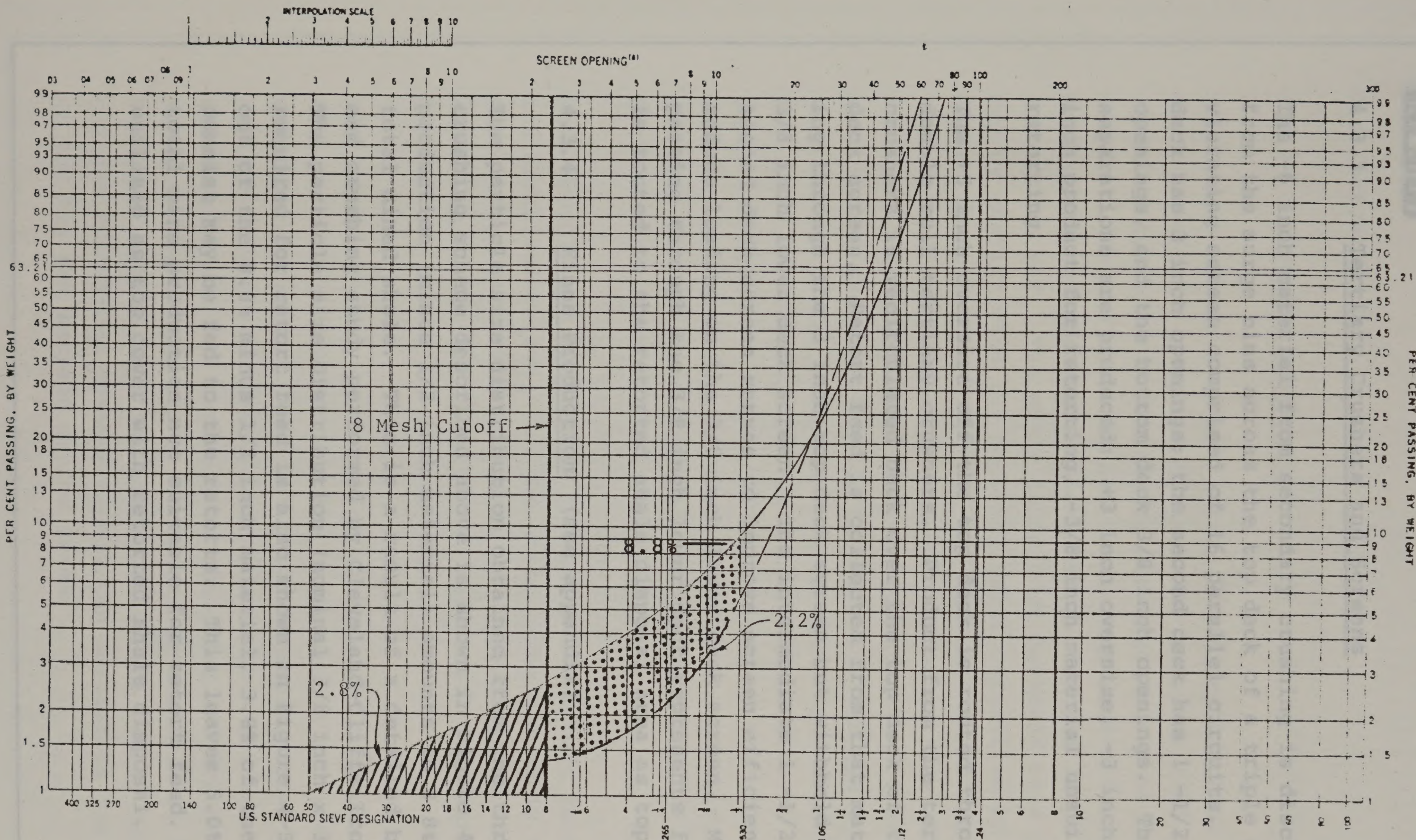
The raw shale crushing and screening facilities will be designed to produce a retort feed consist (nominal 3/8 inch x 3 inch) as shown in Figure 4-5.

4.3.1 Raw Shale Stockpiles

Retort feed preparation will begin with hoisting the -12 inch primary crusher product from the mine to the surface for diversion to either the plant surge pile or to a 625,000 ton stockpile. The stockpile will serve as storage for excess mine production to be used during non-productive periods of the mine and as surge capacity when a retort or retort battery is down for scheduled maintenance. The plant surge pile has a capacity of 7000 tons and prevents loss of feed to the secondary crushers.

4.3.2 Secondary Crushers

Primary crushed material (-12 inch) passes over a vibrating grizzly screen with 6" openings. The +6 inch oversize reports to a double roll secondary crusher to be crushed to -6 inch. Secondary crushing is divided into 3 circuits (2 operating, 1 stand-by). The 6 inch undersize from the grizzly screen is combined with the secondary crusher product and conveyed to surge bins.



Retort Feed & Three Stage Crushing Particle Distribution

Three Stage Crushing ________

Retort Feed - - - - - -

Figure 4-5

4.3.3 Tertiary Crushers and Screens

The -6 inch material from secondary crushing is discharged from the surge bins across the top deck of a triple deck vibrating screen comprised of 16 parallel circuits. The top deck has 3 inch openings; the second deck has 1 -1/2 inch openings, and the bottom deck 3/8 inch openings. Thus, three separations are produced: +3 inch oversize, -3 inch to +3/8 inch product for retorting, -3/8 inch material unsuitable for retorting.

The +3 inch oversize off the top deck is routed through eight double roll tertiary crushers. Product from the tertiary crushers is recirculated back over the top deck of the triple deck screen. Retort feed is collected from that material passing through the 3 inch top deck screen but withheld by the 3/8 inch lower deck screen. The intermediate 1 -1/2 inch second deck screen serves to improve screen efficiency and reduce loading on the 3/8 inch lower deck screen. Material passing through the 3/8 inch lower deck represents fines and is routed to the retorted shale disposal area as top cover.

4.3.4 Fines Production (see appendix)

The particle size distribution obtained from the three stage crushing scheme described above is shown in Figure 4-5. Fines production (minus 1/2 inch material) amounts to 8.8% of the total mined shale. This is a result of a detailed blasting and crushing study performed by Cleveland-Cliffs Iron Company. The particle size distribution (nominal 3/8 inch x 3 inch) required for retort feed is also shown in Figure 4-5. Thus, out of the 8.8% minus 1/2 inch material, 3.8% of the larger consist may be fed to the retorts. This leaves 5.0% of the total mine production not suitable for retort feed. This is utilized as top cover with retorted shale disposal.

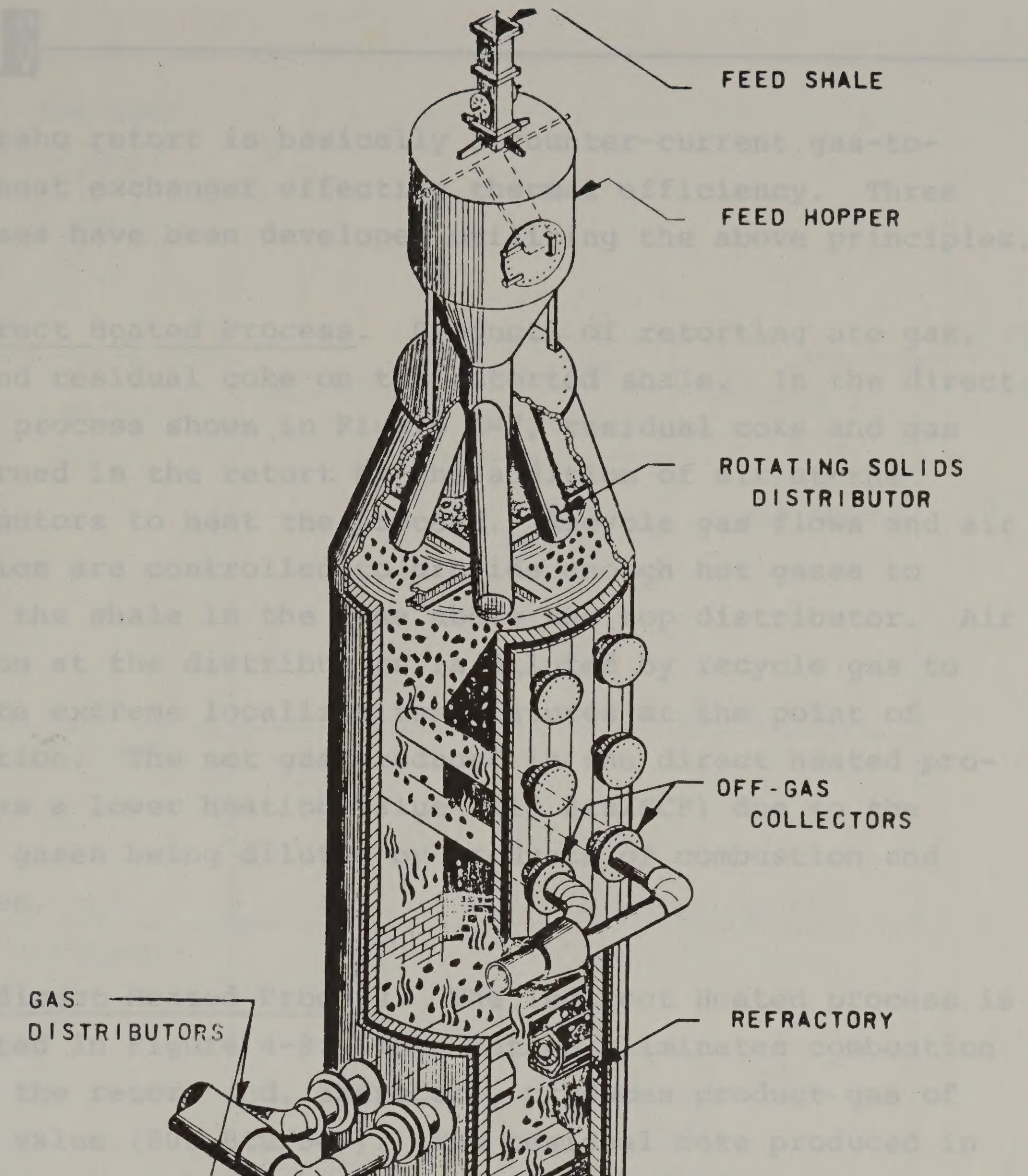
4.4 RETORTING

4.4.1 Process Description

The Paraho retort is a refractory lined, cylindrical vertical shaft vessel for processing lump size (nominal 3/8" x 3") shale. Figure 4-6 exhibits the construction to be described herein. The raw shale is fed in the top from a feed hopper and rotating distributor which distributes the lumps evenly across the bed. The shale lumps move downward as a packed bed by gravity with the movement being controlled by the unique grate in the bottom of the retort. In moving downward, the shale first passes the off-gas collector zone, then through a retorting zone (thermal decompostion of kerogen to oil vapor), over the gas distributors and through a cooling zone to the grate. The grate is operated hydraulically and its speed is controlled to give the desired flow of the shale through the retort. The grate causes the column of material to descend uniformly over the cross-section of the retort. The retorted shale is discharged through a pressure seal at the bottom of the retort.

Cool recycle gas enters the bottom of the retort through gas distributors built in the grate. The gas as it ascends through the shale bed is heated by descending retorted shale, which in turn is cooled. Additional heat enters through two levels of gas distributors.

Two levels of heat distribution are used to completely distribute heat uniformly over the cross-secton and prevent cold gas channeling. The hot gases ascending above the distributors preheat and retort the shale. The ascending gases and shale oil vapors from retorting are cooled by incoming raw shale; oil is condensed in the form of a stable mist and carried with the gases out of the retort through off-gas collection devices to oil/gas separators for recovery of the oil and recycle of the gases.



PARAHO COMMERCIAL EVALUATION STUDY

TITLE

PARAHO RETORT

McKee ENGINEERS AND CONSTRUCTORS CLEVELAND, OHIO

FIG.4-6

The Paraho retort is basically a counter-current gas-to-shale heat exchanger effecting thermal efficiency. Three processes have been developed utilizing the above principles.

The Direct Heated Process. Products of retorting are gas, oil, and residual coke on the retorted shale. In the direct heated process shown in Figure 4-7, residual coke and gas are burned in the retort by the addition of air at the distributors to heat the process. Recycle gas flows and air injection are controlled to provide enough hot gases to retort the shale in the zone above the top distributor. Air addition at the distributors is diluted by recycle gas to moderate extreme localized temperatures at the point of combustion. The net gas produced in the direct heated process has a lower heating value (118 Btu/SCF) due to the retort gases being diluted by products of combustion and nitrogen.

The Indirect Heated Process. The Indirect Heated process is presented in Figure 4-8. This method eliminates combustion within the retort and, therefore, produces product gas of higher value (808 Btu/SCF). The residual coke produced in retorting remains on the retorted shale. The process heat is supplied by recycling gas through heaters, and the hot gas is then injected into the retort at the two distributor levels. The temperature and quantity of the entering hot gases are controlled to provide sufficient heat to retort the shale above the top distributor when combined with the ascending preheated gases added at the grate.

The Combination Process. The combination process uses both hot gas addition at the top distributor and air injection at the mid distributor (refer to Figure 4-9). Air injection at the mid distributor allows utilization of the residual carbon by combustion to assist the top gas heaters in fueling the

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The Indirect Heated Process. The Indirect Heated process is presented in Figure 4-8. This method eliminates combustion within the retort and, therefore, produces product gas of higher value (868 Btu/SCF). The residual coke produced in retorting remains on the retorted shale. The process heat is supplied by recycling gas through heaters, and the hot gas is then injected into the retort at the two distributor levels. The temperature and quantity of the entering hot gases are controlled to provide sufficient heat to retort the shale above the top distributor when combined with the ascending preheated gases added at the grate.

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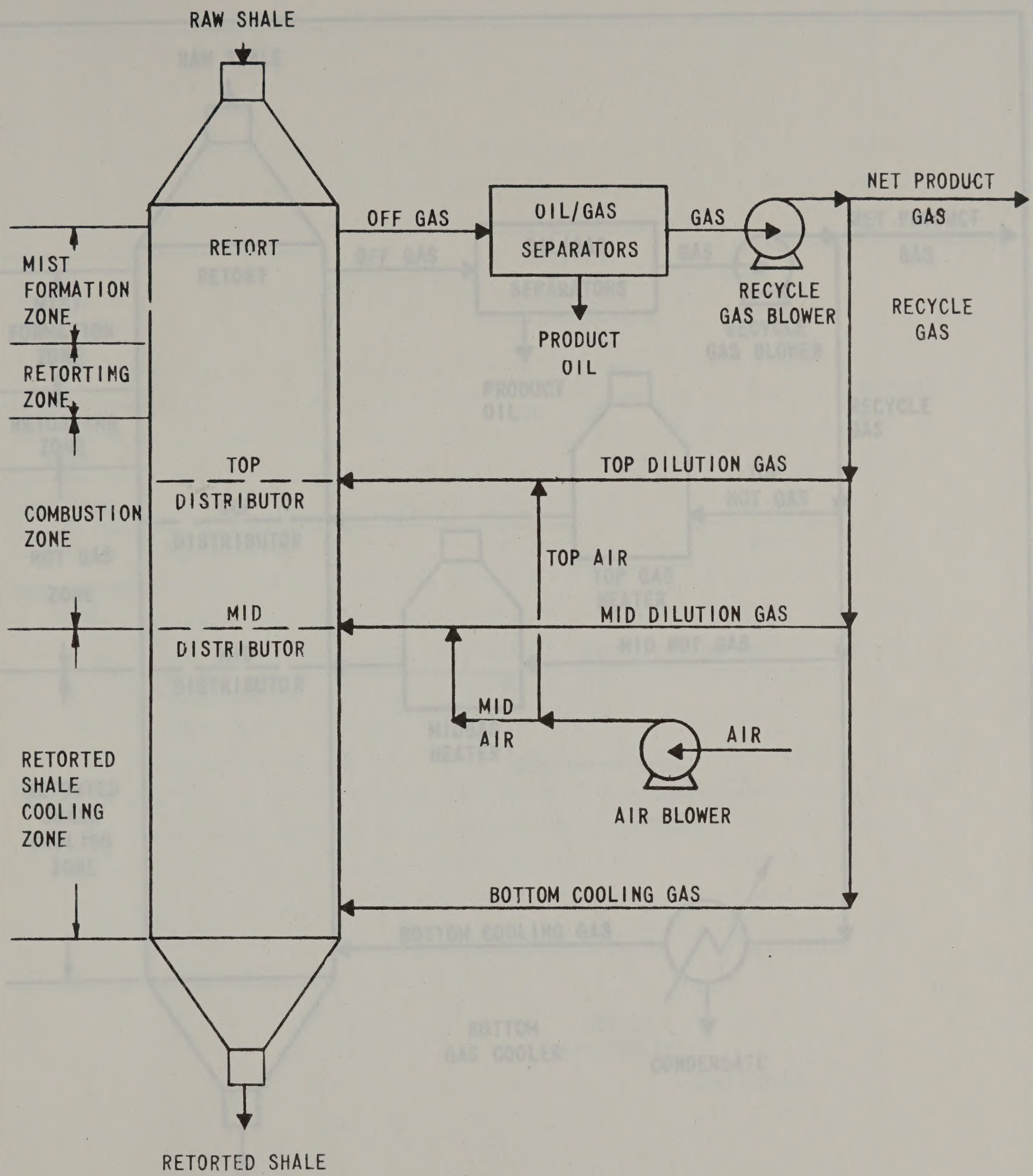

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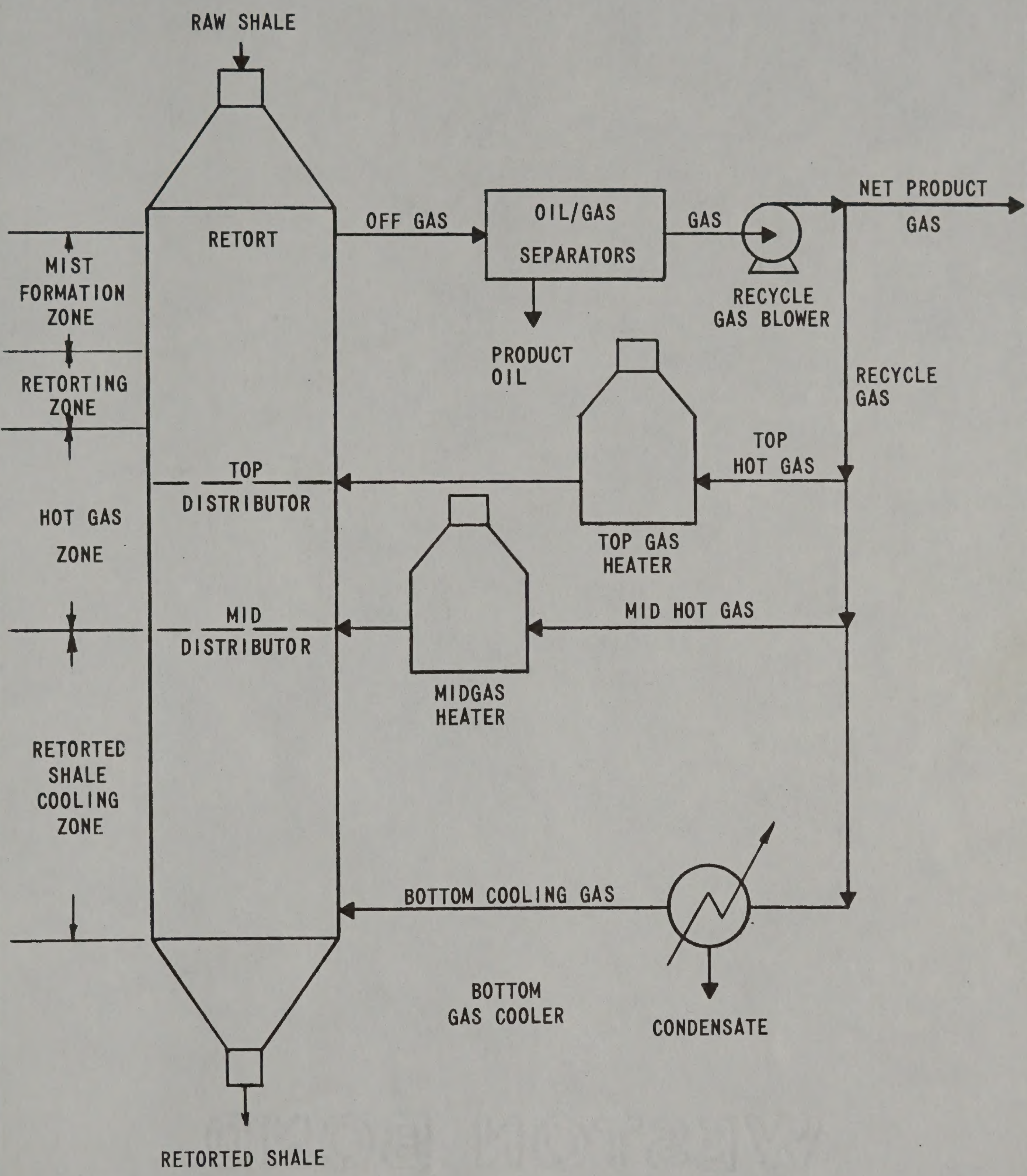
PARAHO COMMERCIAL EVALUATION STUDY

PARAHO DIRECT HEATED PROCESS

McKee ENGINEERS AND CONSTRUCTORS CLEVELAND, OHIO

FIG. 4-7

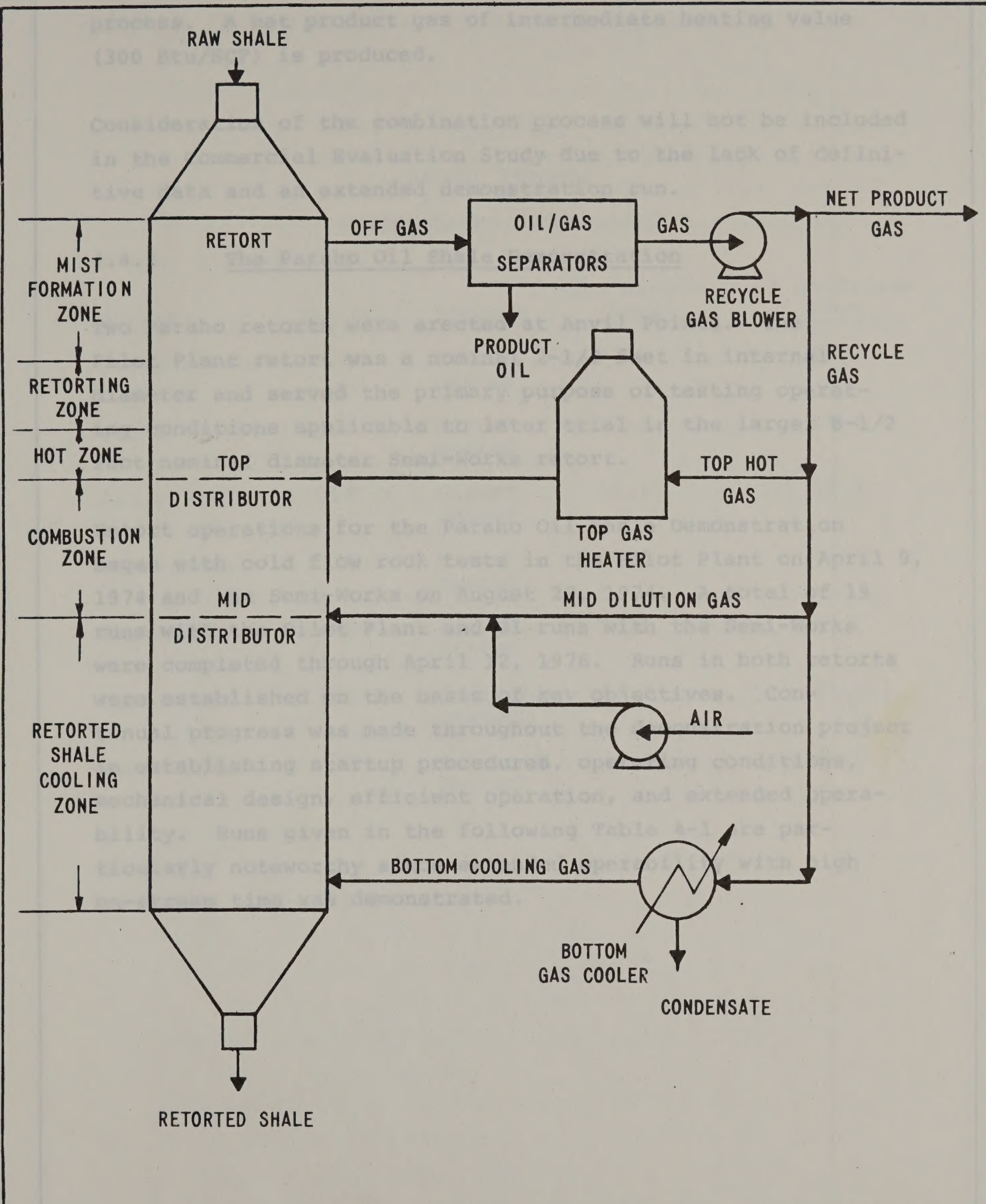


PARAHO COMMERCIAL EVALUATION STUDY

TITLE
PARAHO INDIRECT HEATED PROCESS

McKee
ENGINEERS AND CONSTRUCTORS
CLEVELAND, OHIO

FIG. 4-8



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PARAHO COMMERCIAL EVALUATION STUDY

PARAHO COMBINATION HEATED PROCESS

McKee ENGINEERS AND CONSTRUCTORS CLEVELAND, OHIO

FIG. 4-9

process. A net product gas of intermediate heating value (300 Btu/SCF) is produced.

Consideration of the combination process will not be included in the Commercial Evaluation Study due to the lack of definitive data and an extended demonstration run.

4.4.2 The Paraho Oil Shale Demonstration

Two Paraho retorts were erected at Anvil Points. The Pilot Plant retort was a nominal 2-1/2 feet in internal diameter and served the primary purpose of testing operating conditions applicable to later trial in the larger 8-1/2 foot nominal diameter Semi-Works retort.

Retort operations for the Paraho Oil Shale Demonstration began with cold flow rock tests in the Pilot Plant on April 9, 1974 and the Semi-Works on August 23, 1974. A total of 19 runs with the Pilot Plant and 31 runs with the Semi-Works were completed through April 12, 1976. Runs in both retorts were established on the basis of key objectives. Continual progress was made throughout the demonstration project in establishing startup procedures, operating conditions, mechanical design, efficient operation, and extended operability. Runs given in the following Table 4-1 are particularly noteworthy since extended operability with high on-stream time was demonstrated.

TABLE 4-1

PARAHO RETORTS

DEMONSTRATED OPERABILITY

Retort	Run No.	Process	Run Length (Days)	% On-Stream Time
Pilot Plant	16	Direct Heated	77.0	99.1
Pilot Plant	18	Direct Heated	27.3	94.6
Pilot Plant	19	Direct Heated	12.1	99.8
Semi-Works	7	Direct Heated	56.0	88.4
Semi-Works	20	Direct Heated	25.6	99.7
Semi-Works	23	Indirect Heated	31.2	99.6
Semi-Works	28	Indirect Heated	10.6	100.0

4.4.3 Criteria for Design Basis Selection

Selection of a commercial design basis for Direct Heated and Indirect Heated retorting was based on analysis of the Semi-Works and Pilot Plant runs and test periods within the runs. Key criteria used in the selection of a run or test period applicable to the selection of a commercial design basis were as follows:

1) Run length or test period duration should be of extended length. On-stream time during the run should be high.

2) Test periods should preferably be consecutive and under closely similar operating conditions. A retest of operating conditions is desirable to verify data reproducibility.

3) Operation should have minimal upsets particularly those process related.

4) Post-run inspection of the retort and auxiliary equipment should be satisfactory. The retort should be free of agglomerations; air/gas distributor holes should be open; off-gas piping and oil recovery equipment should be free of sludge.

5) Oil yield should be high.

6) Mass rates should be reasonably high.

7) Operation should be thermally efficient.

8) Data and sample collection should be reliable and laboratory analysis sound.

9) Operating conditions should be as economically viable as possible.

10) A design basis derived from the Semi-Works retort would be preferable since the scale-up factor to a commercial retort is less than with the Pilot Plant.

4.4.4 Design Basis - Direct Heated Process

Semi-Works Run No. 20 (SW-20) best satisfies the criteria listed previously. Run length and interruptions to operating time are given in Table 4-2, Summary of Operating Time. Test period conditions during the run were designed to explore various air ratios to the top and middle air/gas distributors. Five consecutive 24 hour test periods designated as Test A conditions using 82% of total air to the top air/gas distributor and 18% in the middle air/gas distributor were obtained. Operation during the five days was stable with the exception of two brief power failures, the effects of which were negligible. Toward the end of Run No. 20, a retest of Test A conditions was made for five consecutive 24 hour test periods to verify data reproducibility.

The post-run inspection was satisfactory. The retort internals showed no evidence of agglomerated material in the retort or indicated from markings on the refractory walls. The refractory walls were clean and polished from shale movement but without evidence of coke or shale adhering to the walls or erroding the refractory. The outside surface of the air/gas distributors were clean and orifice holes were open and clear of coke or buildup from the run. The off-gas collectors and external piping manifold were clean and free of sludge buildup.

The reliability of data taken during Semi-Works Run No. 20 is considered as excellent. The number of laboratory samples taken both routine and special were extensive. The results

TABLE NO. 4-2

SEMI-WORKS RUN NO. SW-20

SUMMARY OF OPERATING TIME

DATE	OPERATING TIME HOURS	TIME ON-STREAM DAYS	TIME ON-STREAM HOURS	TIME LOST TIME DAYS	TIME LOST TIME HOURS	REMARKS OR REASON FOR OUTAGE
11-04-75	2143					Fire Off
11-07-75	1145	2	14.02		0.13	Power Failure
11-09-75	0405	1	16.20		0.07	Power Failure
11-14-75	1100	5	6.85		0.33	Power Failure
11-17-75	1558	3	4.63		0.82	Standby to repair splice on ret. shale conveyor.
11-18-75	1127		18.67		0.22	Power Failure
11-28-75	1055	9	23.25		0.02	Power Failure
11-30-75	1140	2	0.73		--	Shutdown
	TOTAL	25	12.36		1.59	99.74% operating time

of oil rundown tank calibrations, raw shale and retorted shale weigh belt checks, and gas losses through the rotary discharge seals were all incorporated into the data. Product gas samples were taken and analyzed by Atlantic Richfield Company. Oil samples were sent to Sohio Petroleum Company for crude assay. (For details see Appendix.)

The core of the commercial design basis for Direct Heated retorting was formulated by combination of the test periods run under Test A conditions. A review of all data from Test A conditions is summarized in Table 4-3. Test period A-6 and A-7 were excluded since the operating conditions deviate from the other Test A periods to a greater degree. The repeatability of the data and degree of control are indicated by the standard deviations. This combination of test periods represents 303 stable operating hours. A data summary calculated by weight averaging the individual test period data on the basis of test period length is given in Table 4-4.

Design parameters for the commercial retort were basically extracted from the data summary Table 4-4. Various figures were rounded off. The following design parameters differ from those in Table 4-4, and justification and reason for such deviations are described.

<u>Shale Grade</u>. A shale grade of 29 gallons per ton was dictated for the Commercial Evaluation Study because it is a physical feature of the site selection. During Semi-Works Run No. 20, 32 out of 139 eight hour periods (23%) operated with greater than 29 gallon per ton shale feed; similarly, 29 out of 128 (23%) in Pilot Plant Run No. 16, 10 out of 24 (42%) in Pilot Plant Run No. 19. Both retorts also had excursions in shale grade of greater than 30 gpt for several eight hour periods. Based on the above, sustained operation with 29 gpt shale is feasible.

TABLE NO. 4-3

DEVIATION OF OPERATING VARIABLES AND YIELDS
SEMI-WORKS RUN NO. SW-20 TEST A CONDITIONS
TESTS NOS. A-1, 2, 3, 4, 5, 9, 10, 11, 12
13, 14, 15 AND 16

ITEM	MEAN	STANDARD DEVIATION
Raw Shale Rate, TPH	11.17	0.27
Raw Shale F.A., GPT	27.21	0.52
Oil Yield (DRY), GPH	277.40	9.67
Oil Water Content, WT%	4.84	2.58
Oil Yield, Vol% F.A.	91.27	4.48
Oil Yield, Wt% F.A.	91.56	4.53
Air to Top Dist., SCFM	709.29	7.95
Air to Mid Dist., SCFM	158.24	1.96
Gas to Top Dist., SCFM	253.19	3.09
Gas to Mid Dist., SCFM	245.74	3.72
Gas to Bottom Dist., SCFM	2254.48	23.37
Gas to Product, SCFM	1340.40	27.54

TABLE NO. 4-4

DATA SUMMARY

Sheet 1 of 2

Run No.	SW-20
Test No. Combined	A-1,2,3,4 5,9,10,11, 12,13,14,15 & 16
Length, Hours	303

RATES AND QUANTITIES

Air	
Top SCF/Ton	3810
Mid SCF/Ton	850
Bottom SCF/Ton	0
Total SCF/Ton	4660
Recycle	
Top SCF/Ton	1360
Mid SCF/Ton	1320
Bottom SCF/Ton	12110
Total SCF/Ton	14790
Raw Shale Tph	11.17

TEMPERATURES

Product Oil Out °F	139
Retorted Shale Out °F	384
Raw Shale In °F	36
Air °F	184
Product & Recycle Gas °F	241
Offgas Temperature °F	145
Dist. Cooling H_2O In, °F	116
Dist. Cooling H_2O Out, °F	134

YIELDS

Oil Collected Gal/Ton	24.82
Oil Collected Vol% F.A.	91.27
Product Gas SCF/Ton	7200
Retorted Shale Wt% R.S.	81.0
Retorted Shale Tph	9.05
Liquid Water lbs/Ton	9.67
Material Recovery Wt%	99

MISCELLANEOUS

Retort dp in H_2O/ft bed	1.00
Carbonate Decomp. Wt%	27
Retort Bed Height, Ft.In.	25'-6"
Throughput, lbs/hr/ft^2	454
Barometric Press. In Hg.	23.94
Relative Humidity % (Air)	61
Ambient Air °F	36

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TABLE 4-4 - Cont.

DATA SUMMARY

Sheet 2 of 2

Run No. SW-20
Test No. Comb. Test A's

RAW SHALE PROPERTIES

Moisture Content Wt%	0.96
Fischer Assay Gal/Ton	27.2
F.A. Wt% Oil	10.39
F.A. Wt% Water	1.66
F.A. Wt% Gas + Loss	2.29
Mineral CO_2 Wt%	17.71
Ignition Loss Wt%	33.07
Carbon Wt%	17.05
Hydrogen Wt%	1.84
Nitrogen Wt%	0.51

PRODUCT OIL PROPERTIES

Gravity, Deg. API	21.4
Viscosity SUS @ 130°	89.9
Viscosity SUS @ 210°	46.5
Ramsbottom Carbon Wt%	1.73
Water Content Vol%	4.46
Solids, BS, Wt%	0.47
Carbon Wt%	84.62
Hydrogen Wt%	11.50
Nitrogen Wt%	2.00

PRODUCT GAS PROPERTIES (Dry)

Gross Heat. Value Btu/scf	118
Specific Gravity	1.1

RETORTED SHALE PROPERTIES

Fischer Assay Gal/Ton	0.28
Mineral CO_2 Wt%	15.86
Organic Carbon Wt%	1.97
F.A. Wt% Oil	0.10
F.A. Wt% Water	0.16
F.A. Wt% Gas + Loss	0.29
Ignition Loss Wt%	17.72
Carbon Wt%	6.30
Hydrogen Wt%	0.17
Nitrogen Wt%	0.21

SCREEN ANALYSIS

Size - Inches	Amount - Wt%
3.00	0
2.50	2.1
2.00	13.1
1.50	32.8
1.05	21.7
0.742	15.3
0.525	9.9
0.371	1.4
0.263	1.3
0.185	0.5
0.093	0.7
Pan	1.2
Loss	0

GAS ANALYSIS, VOL% (Dry)

H_2	2.50
N_2	65.45
O_2	0.01
CO	2.51
CH_4....................	2.19
CO_2....................	24.14
C_2H_4	0.67
C_2H_6	0.62
C_3's	0.71
C_4's	0.36
C_5+s	0.41
H_2S	0.22
NH_3	0.21
VOL% Moisture	17.55

Shale Mass Rate. Raw shale throughput for the combined Test A periods of Semi-Works Run No. 20 averaged 11.17 tons per hour (dry) or 453.6 lb/hr/ft^2. Shale mass rate for the Commercial Evaluation Study has been adjusted to 455.5 lbs/hr/ft^2 for the purpose of having a discrete number of retorts (24) and 100,000 BPSD crude shale oil production. Four batteries of six retorts will be used.

Product Gas Quality. Product gas quality (dry, H_2S, NH_3 Free) is based on Atlantic Richfield Company's sampling and analysis of the product gas during Semi-Works Run No. 20. ARCO's gas samples were taken on 11/25/75 during test period A-13. (See Appendix for details.) Concentration of hydrogen sulfide, ammonia, and water were included from the average values measured by the Paraho laboratory.

Product Oil Properties. Oil samples were taken during Semi-Works Run No. 20. Sohio Petroleum Company performed a final limited assay of this crude shale oil and have supplied the results for the purposes of the Commercial Evaluation Study. (See Appendix for details.)

Raw Shale Feed Screen Analysis. Tylab screen analysis for raw shale feed during the combined Test A periods of Semi-Works Run 20 averaged as given in Table 4-4. As the basis for the blasting and crushing study performed by Cleveland-Cliffs Iron Company to determine fines production, (the results of which were described in Section 4.3), a two-day (11/10/75 - 11/12/75) average screen analysis was taken during Semi-Works Run No. 20. This screen analysis is nearly equivalent, particularly in the percentage of fines, to the combined Test A average. Thus, to prevent discrepancy with the blasting and crushing study, the two-day screen analysis will be used for commercial retort feed.

In Table 4-5, the commercial design basis for the Paraho Direct Heated process is summarized utilizing the information from Table 4-4 with the modifications described above.

4.4.5 Design Basis - Indirect Heated Process

The following discussion will cite two Semi-Works runs which were significant in formulating a commercial retort design basis for indirect heated retorting.

Semi-Works Run Number 23. Semi-Works Run No. 23 (SW-23) demonstrated extended operability. A variable study to improve thermal efficiency was made as the run progressed. The run length and interruptions to operating time are given in Table 4-6. As mentioned above, the test periods were designed to progressively improve thermal efficiency as shown in Table 4-7. Thermal efficiency was basically accomplished by shifting total recycle gas input from the top distributor to the bottom distributor with corresponding increase in the top gas temperature. Thus, the recovery of heat in the retorted shale was greater. A measure of thermal efficiency is the enthalpy of the top distributor gas, since this represents energy the external recycle gas heaters must supply.

Semi-Works Run Number 28. Semi-Works Run No. 28 (SW-28) concentrated on retesting and further improving the thermal efficiencies of the later test periods of Semi-Works Run No. 23. The percentage on-stream time was 100% for the 10.6 day period. Three momentary (less than 5 minutes) heater outages did occur, but their effect is considered negligible. Test periods were designed in an effort to determine the operating conditions that minimize carbonate decomposition yet exhibit complete retorting resulting in maximum thermal efficiency. Table 4-8 shows the results of those test

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TABLE NO. 4-5

PARAHO DIRECT HEATED RETORT

COMMERCIAL DESIGN BASIS

Rates and Quantities

Shale Mass Rate, $lbs/hr/ft^2$	455.5
Air to Top Distributor, SCF/Ton	3810
Air to Middle Distributor, SCF/Ton	850
Total Air, SCF/Ton	4660
Recycle to Top Distributor, SCF/Ton	1360
Recycle to Middle Distributor, SCF/Ton	1320
Recycle to Bottom Distributor, SCF/Ton	12110
Total Recycle, SCF/Ton	14790
Distributor Cooling Water, gal/ton	430

Yields

Raw Shale Grade, gpt	29
Oil Collected, Vol.% Fischer Assay	92
Product Gas, SCF/Ton	7200
Retorted Shale, wt.% Raw Shale	81

Temperatures

Offgas, ^oF	150
Retorted Shale, ^oF	380
Distributor Cooling Water Rise, ^oF	18

PRODUCT GAS:

	Wet Vol%	Dry Vol%
H_2	3.59	4.36
O_2 + Ar	0.76	0.92
N_2	52.89	64.15
Cl	1.90	2.30
CO	1.63	1.98
CO_2	17.93	21.75
C_2 (E)	0.76	0.92
C_2	0.78	0.94
C_3 (E)	0.37	0.45
C_3	0.39	0.47
C_4s (MW=57.0)	0.33	0.40
C_5s (MW=71.5)	0.13	0.16
C_6+ (MW=96.2)	0.63	0.77
H_2S	0.18	0.22
NH_3	0.17	0.21
H_2O	17.56	--
	100.00	100.00

PRODUCT OIL:

Gravity, ^{O}API	21.2
Specific Gravity @ 60^{O}F	0.9267
Pourpoint, ^{O}F	80
Viscosity	
SUS @ 60^{O}F	Too Heavy
SUS @ 100^{O}F	162.9
SUS @ 140^{O}F	71.0
SUS @ 210^{O}F	41.3
Total Sulfur, Wt%	0.63
Total Nitrogen, Wt%	1.90
Ramsbottom Carbon, Wt%	1.59
BS & W, Vol%	0.14
Carbon, Wt%	84.20
Hydrogen, Wt%	11.69
Oxygen, Wt%	1.24

Paraho

MISCELLANEOUS

Retort Pressure Drop, Inches H_2O/foot bed	1.0
Retort Bed Height, feet-inches	25-6
Raw Shale Feed Screen Analysis	Figure 4-5

TABLE NO. 4-6
SEMI-WORKS RUN NO. SW-23
SUMMARY OF OPERATING TIME

DATE	OPERATING TIME HOURS	TIME ON-STREAM DAYS	TIME ON-STREAM HOURS	TIME LOST-TIME DAYS	TIME LOST-TIME HOURS	REMARKS OR REASON FOR OUTAGE*
1-10-76	0800					Startup
1-15-76	1018	5	2.30		0.37	Heater off 5 times
1-19-76	0750	3	21.17		0.07	Heater off
1-24-76	2040	5	12.77		1.17	Heater off 7 times
1-25-76	0145		3.92		7.25	Heater off - standby
1-26-76	1100	1	2.00		3.76	Standby to install gas cooler
1-26-76	1747		3.03		0.22	Heater off
1-27-76	2030	1	2.50		2.50	Heater off
1-29-76	0920	1	10.33		0.33	Heater off
1-30-76	0100		15.33		0.08	Heater off
1-30-76	0410		3.08		0.08	Heater off
1-30-76	0430		0.25		0.08	Heater off
1-30-76	0530		0.92		0.08	Heater off
1-30-76	0610		0.58		0.08	Heater off
1-30-76	1800		11.76		1.33	Heater off
1-31-76	0320		8.00		0.30	Heater off 3 times
1-31-76	0455		1.28		4.83	Heater off
2-5-76	1400	5	4.25		0.17	Heater off
2-6-76	1607	1	1.88		1.00	Standby to check weigh belt
2-9-76	2120	3	4.22		1.83	Heater off
2-10-76	1321		14.18			Shutdown
	TOTAL	30	3.76	1	1.52	96.6% Operating Time

*Includes heater outage of 5 minutes or more.

TABLE NO. 4-7
SEMI-WORKS RUN SW-23
THERMAL EFFICIENCY PROGRESSION

Test Period	Heat Input* MBTU/Ton	Recycle Gas** Ratio	Top Gas Temp., °F
A-1	610	3.68	1142
A-2	609	3.79	1148
A-3	641	3.72	1148
A-4	628	3.72	1151
A-5	617	3.77	1143
A-6	592	3.79	1148
A-7	578	2.00	1136
B-1	617	2.57	1146
B-2	603	2.59	1141
A-8	661	3.73	1133
B-5	532	1.94	1151
C-1	516	1.79	1183
C-2.1	485	1.47	1206
C-2.2	444	1.45	1153
C-2.3	487	1.46	1198
C-5	461	1.39	1206

*Heat input defined as top gas enthalpy at the distributor inlet temperature above a 77°F datum.

**Recycle gas ratio defined as ratio of top gas rate (SCF/ton) to bottom gas rate (SCF/ton).

TABLE NO. 4-8

SEMI-WORKS RUN NO. SW-28

THERMAL EFFICIENCY STUDY

Test Period	Heat Input* MBTU/Ton	C_5+ Yield Wt% Fischer Assay	Organic Carbon in Retorted Shale, Wt%
C-1	478	91.3	3.30
C-2	451	88.4	3.79
Step 3	348	60.4	5.52
A-3	341	60.1	5.93
A-4	392	85.4	4.16
A-4.1	440	94.9	3.10
A-4.2	424	94.0	3.04
A-4.3	397	79.7	3.74
A-4.4	386	69.5	5.51

*Heat input defined as top gas enthalpy at the distributor inlet temperature above a 77°F datum.

periods where heat input was purposely insufficient as evident from low Fischer Assay yields and high organic carbon content remaining in the retorted shale. Organic carbon contents in the vicinity of 2.5 weight% represent complete retorting.

The reliability of the data during Semi-Works Runs No. 23 and 28 is considered to be excellent with respect to the frequency and accuracy of readings taken and laboratory samples analyzed. The results of oil rundown tank calibrations and rotary seal losses obtained during Semi-Works Run No. 20 were incorporated into these data. Raw shale weigh belt checks were made when necessary. Retorted shale weights were determined by ash balance. Oil samples were taken during Semi-Works Run No. 23 and sent to Sohio Petroleum for crude assay. It should be noted that operation with simultaneous hot gas injection to both top and mid gas distributors was not possible during these runs due to limitations in the recycle gas heaters.

Analysis of the test period data from Semi-Works Runs No. 23 and 28, with the criteria given in Section 4.4.3, resulted in selection of the consecutive test periods A-4.1 and A-4.2 of Semi-Works Run No. 28 as the core of the commerical design basis for the Indirect Heated process. Combination of these two test periods represents 36 stable operating hours of high yield and thermal efficiency. A data summary calculated by weight averaging the two test periods data on the basis of test period length is given in Table 4-9.

Design parameters for the commerical retort were basically extracted from the Data Summary Table 4-9. Various figures were rounded off. The following design parameters differ from those in Table 4-9 and justification and reason for such deviations are described.

Shale Grade. As stated previously, a shale grade of 29 gpt was a physical feature of the site selection made for the Commercial Evaluation Study. During Semi-Works Run No. 23, 16 out of 71 eight hour periods (23%) operated with greater than 29 gpt shale feed; similarly, 2 out of 22 (9%) in Semi-Works Run No. 28. Excursions of greater than 30 gpt shale feed were experienced during Semi-Works Run No. 23. Based on the above, sustained operation with 29 gpt shale is feasible.

Shale Mass Rate. Raw shale throughput for the combined test periods A-4.1 and A-4.2 of Semi-Works Run No. 28 averaged 414 $lbs/hr/ft^2$. For the purpose of the Commercial Evaluation Study, shale mass rate for the Indirect Heated process will be the same as that for the Direct Heated process, 455.5 $lbs/hr/ft^2$. Explanation of the basis for 455.5 $lbs/hr/ft^2$ was given previously for the Direct Heated process. Indirect Heated operation at 455.5 $lbs/hr/ft^2$ was demonstrated during Semi-Works Runs No. 23 and 28.

Product Gas Quality. Atlantic Richfield Company obtained and analyzed samples of the product gas during Semi-Works Run No. 28, however, the results were not available when work on the Commercial Evaluation Study was initiated. The gas analysis used in commercial evaluation study, for the Indirect Heated process will be as sampled and analyzed by the Paraho laboratory during the A-4.1 and A-4.2 test periods of Semi-Works Run No. 28. The data summary of test periods A-4.1 and A-4.2 shown in Table 4-9 present the gas analysis on a C_4- basis. The corresponding oil yield is reported as C_5+ wt% of Fischer Assay. For the Commercial Evaluation Study, oil yield will be as collected and gas quality will be as produced. Thus, the gas analysis for the Commercial Evaluation Study will be as given in Table 4-9 with the C_5+ fraction as sampled and analyzed by the Paraho Laboratory included.

TABLE NO. 4-9

DATA SUMMARY

Sheet 1 of 2

Run No.	SW-28
Test No.	A-4.1,A-4.2
Start, Date & Time	3/19/76 2000
End, Date & Time	3/21/76 0800
Length, Hours	36

TEMPERATURES

Product Oil Out ^{O}F	147
Retorted Shale Out ^{O}F	336
Raw Shale in ^{O}F	40
OffGas Temperature ^{O}F	326
Top Heater ^{O}F	1379
Top Dist. Inlet ^{O}F	1299
Bottom Dist. Inlet ^{O}F	150

RATES AND QUANTITIES

Recycle Gas	
Top SCF/Ton	10530
Mid SCF/Ton	0
Bottom SCF/Ton	11950
Total SCF/Ton	22480
Raw Shale Tph	10.2

YIELDS

Oil Collected Gal/Ton	24.24
Oil Collected Vol% F.A.	92.2
Total Oil Yield C_5 + Wt% F.A.	95
Product Gas SCF/Ton (wet)	535
Retorted Shale Tph	9.1
Retorted Shale Wt% R.S.	89.2
Liquid Water Lbs/Ton	29.9
Material Recovery Wt%	100.3

MISCELLANEOUS

Retort dp in H_2O/ft bed	1.4
Carbonate Decomp. Wt%	2.5
Retort Bed Height, Ft.In.	24'-6"
Throughput, Lbs/Hr/Ft^2	414

TABLE NO. 4-9 CONT.
DATA SUMMARY

Sheet 2 of 2

Run No. SW-28
Test No. A-4.1, A-4.2

RAW SHALE PROPERTIES

Moisture Content Wt %	1.23
Fischer Assay Gal/Ton	26.3
F.A. Wt% Oil	10.02
F.A. Wt% Water	1.68
F.A. Wt% Gas + Loss	2.03
Mineral CO_2 Wt%	17.70
Ignition Loss Wt%	32.02
Carbon Wt%	16.16
Hydrogen Wt%	1.70
Nitrogen Wt%	0.45
Sulphur Wt%	0.79

PRODUCT OIL PROPERTIES

Gravity, Deg. API	20.2
Viscosity SUS @ 130°	85.0
Viscosity SUS @ 210°	45.7
Ramsbottom Carbon Wt%	1.93
Water Content Vol%	1.07
Solids, BS, Wt%	1.56
Carbon Wt%	84.89
Hydrogen Wt%	11.44
Nitrogen Wt%	2.03
Sulphur Wt%	0.62

PRODUCT GAS PROPERTIES (Dry) C_4-

Gross Heat. Value Btu/SCF	808
Specific Gravity	0.721

RETORTED SHALE PROPERTIES

Fischer Assay Gal/Ton	0.5
Mineral CO_2 Wt%	19.47
Organic Carbon Wt%	3.06
F.A. Wt% Oil	0.19
F.A. Wt% Water	0.74
F.A. Wt% Gas + Loss	0.62
Ignition Loss Wt%	23.32
Carbon Wt%	8.37
Hydrogen Wt%	0.33
Nitrogen Wt%	0.34
Sulphur Wt%	0.74

SCREEN ANALYSIS

Size - Inches	Amount - Wt%
3.00	0.0
2.50	0.0
2.00	0.0
1.50	26.2
1.05	31.8
0.742	23.2
0.525	13.6
0.371	1.5
0.263	1.4
0.185	0.8
0.093	0.5
Pan	0.9
Loss	0.1

GAS ANALYSIS, VOL% (Dry) C_4-

H_2	25.12
N_2	0.56
O_2	0.0
CO	2.73
CH_4	32.15
CO_2	15.24
C_2H_4	12.74
C_2H_6	4.52
C_3's	2.28
C_4's	0.61
H_2S	2.82
NH_3	1.23
Vol.% Moisture	28.82

Product Oil Properties. Oil samples were taken during Semi-Works Run No. 23. The Sohio Petroleum Company performed a final limited crude assay of this crude shale oil and have supplied the results for the purposes of the Commercial Evaluation Study. (For details see Appendix.)

Time did not allow a complete crude assay to be run on oil produced from test periods A-4.1 and A-4.2 of Semi-Works Run No. 28. Since a complete crude assay is necessary for process calculations in crude shale oil upgrading, the assay from Semi-Works Run No. 23 will be utilized here. It is interesting to note that oils produced during Semi-Works Runs No. 28 and 31 and test periods of higher thermal efficiency in Semi-Works Run No. 23 exhibited lower viscosities as shown in Table 4-10.

Raw Shale Feed Screen Analysis. The Tylab screen analysis for raw shale feed during the combined test periods A-4.1 and A-4.2 of Semi-Works Run No. 28 averaged as given in Table 4-9. In order to utilize the blasting and crushing study performed by Cleveland-Cliffs Iron Company, the two day screen analysis of 11/10/75 to 11/12/75 as described previously in Section 4.4.4 will be assumed as the feed consist for commercial indirect heated operation. Screen analysis for retort feed is shown in Figure 4-5.

Product Gas Production. Product gas production for the combined test periods A-4.1 and A-4.2 of Semi-Works Run No. 28 averaged 535 SCF/Ton wet basis. The quantity includes predicted losses from the top and bottom rotary seals. During the above test periods, leakage of recycle gas in the external heaters was known to exist, but quantitative information on the degree of leakage is not available. Thus, taking into account heater leakages, the gas production for commercial design was conservatively assumed to be 700 SCF/Ton.

TABLE NO. 4-10

SEMI-WORKS RUN NO. SW-23, SW-28, SW-31
Crude Shale Oil Viscosities

Run Number	Test Period	Viscosity @ 130°F, SUS	Viscosity @ 210°F, SUS
SW-23	A-1	105.9	50.4
	A-2	106.0	52.1
	A-3	112.8	53.0
	A-4	94.9	49.1
	A-5	111.9	53.1
	A-6	112.4	53.0
	A-7	112.9	53.4
	B-1	106.6	51.7
	B-2	115.4	56.5
	A-8	102.4	50.5
	B-5	111.0	53.9
	C-1	117.4	53.1
	C-2.1	105.0	58.0
	C-2.2	88.5	51.4
	C-2.3	85.4	49.1
	C-5	89.5	48.9
SW-28	C-1	68.4	42.2
	C-2	66.8	41.6
	Step 3	63.4	41.4
	A-3	63.5	42.5
	A-4	64.6	41.8
	A-4.1	82.9	45.0
	A-4.2	86.1	46.1
	A-4.3	72.2	44.1
	A-4.4	71.5	44.7
SW-31	B	67.0	41.9
	D	68.2	42.1

Shale Bed Pressure Drop. The bed pressure drop for test periods A-4.1 and A-4.2 for Semi-Works Run No. 28 was unusually high compared with similar operating test periods. The higher pressure drop during the combined A-4.1 and A-4.2 test periods indicates the possibility of internal restriction to gas flow within the retort. A shale bed pressure drop of 1.0 inch of water per foot of bed is considered more typical of Indirect Heated operation and will be used for commercial retort design.

In Table 4-11, the commercial design basis for the Paraho Indirect Heated process is summarized utilizing the information from Table 4-9 with the modifications described above.

4.4.6 Commercial Retorts

Process Flow Diagrams. Process flow diagrams for the Direct and Indirect Heated commercial retorts are shown in Figures 4-11 and 4-12, respectively. The process flow and material balances were derived from the retort design basis given in Sections 4.4.4 and 4.4.5 and standard engineering practice. Preliminary sizes are given for major equipment and lines for the purpose of cost estimating.

TABLE NO. 4-11

PARAHO INDIRECT HEATED RETORT
COMMERCIAL DESIGN BASIS

Rates and Quantities:	
Shale Mass Rate, lbs/hr/ft^2	455.5
Recycle to Top Distributor, SCF/Ton	10500
Recycle to Bottom Distributor, SCF/Ton	12000
Total Recycle, SCF/Ton	22500
Top Gas Heat Input, Btu/Ton	429000
Yields:	
Raw Shale Grade, gpt	29
Oil Collected, Vol.% Fischer Assay	92
Product Gas, SCF/Ton	700
Retorted Shale, Wt.% Raw Shale	86.5
Temperatures:	
Offgas, $^{\circ}F$	300
Cooled Offgas, $^{\circ}F$	150
Retorted Shale, $^{\circ}F$	310
Bottom Cooling Gas, $^{\circ}F$	150
Heating Gas, $^{\circ}F$	1300

PRODUCT GAS:

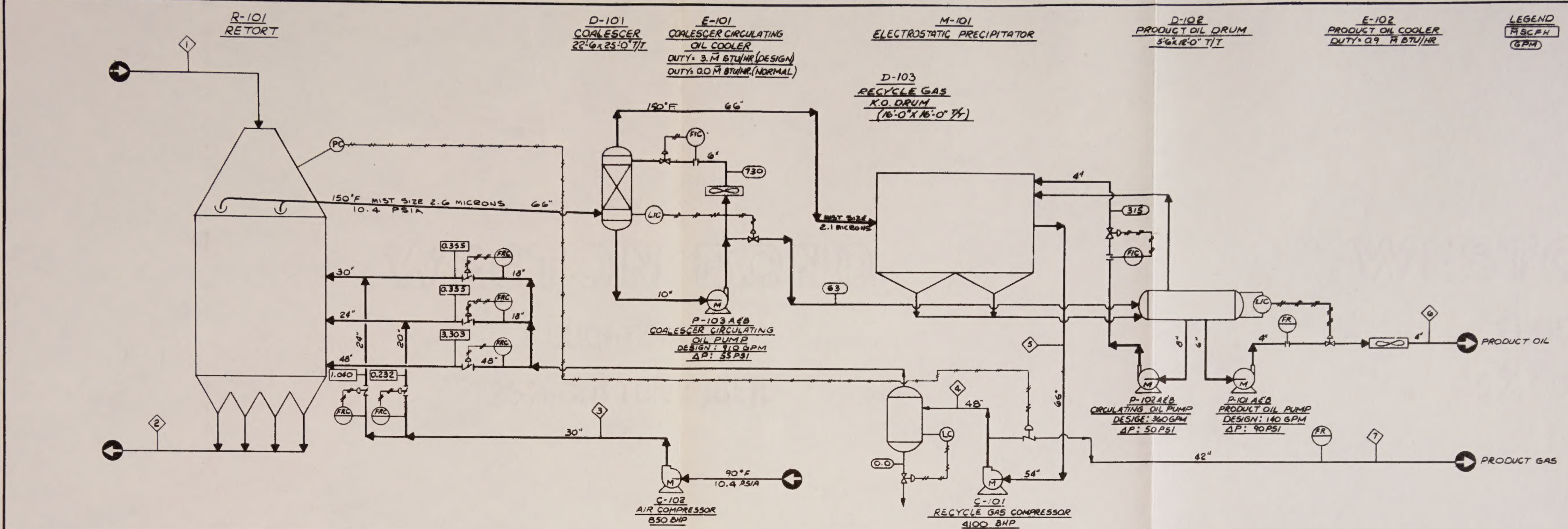
	Wet Vol%	Dry Vol%
H_2	17.40	24.20
N_2 + Ar +O_2	0.36	0.50
C_1	22.53	31.34
CO	1.91	2.66
CO_2	10.57	14.70
C_2E	8.79	12.23
C_2	3.16	4.39
C_3E	1.62	2.25
C_3	Incl. in C_3(E)	Incl. in C_3 (E)
C_4S (mol wt. = 57.0)	0.47	0.65
C_5+ Light Naphtha (MW=100)	1.15	1.60
C_6+ Heavy Naphtha (MW=144)	0.57	0.79
H_2S	2.45	3.41
NH_3	0.92	1.28
H_2O	28.10	--
	100.00	100.00

PRODUCT OIL:

Gravity, ^{o}API	19.1
Specific Gravity @ 60^{o}F	0.9396
Pourpoint, ^{o}F	85
Viscosity	
SUS @ 60^{o}F	Too Heavy
SUS @ 100^{o}F	241
SUS @ 140^{o}F	88.0
SUS @ 210^{o}F	45.0
Total Sulfur, Wt%	0.62
Total Nitrogen, Wt%	2.05
Ramsbottom Carbon, Wt%	1.14
BS & W, Vol%	0.05
Carbon, Wt%	84.88
Hydrogen, Wt%	11.57
Oxygen, Wt%	1.28

MISCELLANEOUS:

Retort Pressure Drop, Inches H_2O/foot bed	1.0
Retort Bed Height, feet-inches	24-6
Raw Shale Feed Screen Analysis	Figure 4-5



STREAM NO. / STREAM NAME	1 RAW SHALE FEED	2 SPENT SHALE	3 PROCESS AIR	4 RECYCLE GAS	5 PRECIPITATOR PRODUCT GAS	6 PRODUCT OIL	7 PRODUCT GAS
TEMPERATURE, °F	50	380	175	225	150	120	225
PRESSURE, PSIA	10.4	10.4	15.0	15.0	10.0	60	12.5
SOLIDS							
LBS/HR.	546600	437975					
TONS/DAY	6559	5256					
GASES							
COMPOSITION MOL./HR.							
N_2			2625	5687.1	8472.6		2785.5
O_2			699	—	—		—
H_2			—	380.6	567.0		186.4
CO			—	172.7	257.3		84.6
CO_2			—	1900.8	2831.8		931.0
CH_4			—	201.3	299.9		98.6
C_2H_4			—	80.6	120.1		39.5
C_2H_6			—	82.7	123.2		40.5
C_3H_6			—	39.2	58.4		19.2
C_3H_8			—	41.2	61.4		20.2
C_4'S (MW = 57.0)			—	34.9	52.0		17.1
C_5'S (MW = 71.5)			—	13.7	20.4		6.7
C_6^+ (MW = 96.2)			—	66.8	99.5		32.7
H_2O			33	1861.4	2773.1		911.7
H_2S			—	19.0	28.3		9.3
NH_3				18.0	26.8		8.8
TOTAL MOL/HR.			3357	10600.0	15791.8		5191.8
LBS./HR.			96510	303925	452786		148861
M̄SCFH			1.272	4.018	5.986		1.968
MW			28.75	28.67	28.67		28.67
LIQUIDS							
BPSD						4167	
LBS/HR.						56274	
API						21.2	
CS @ 100°F						35.0	
CS @ 210°F						4.6	
CS @ COND.						20.0	
WT % S						0.63	
WT % N						1.90	
POUR PT. °F						80	

NOTES: 1) DESIGN BASIS

RETORT THROUGH PUT	456 LB/HR/FT^2
ACTIVE AREA	1200 FT^2
FISHER ASSAY	29 GAL./TON
OIL YIELD	92 % F.A.
GAS YIELD	7200 SCF/TON
RECYCLE GAS	14700 SCF/TON
AIR RATE	4660 SCF/TON
RETORT ΔP	1.0" H_2O/FT

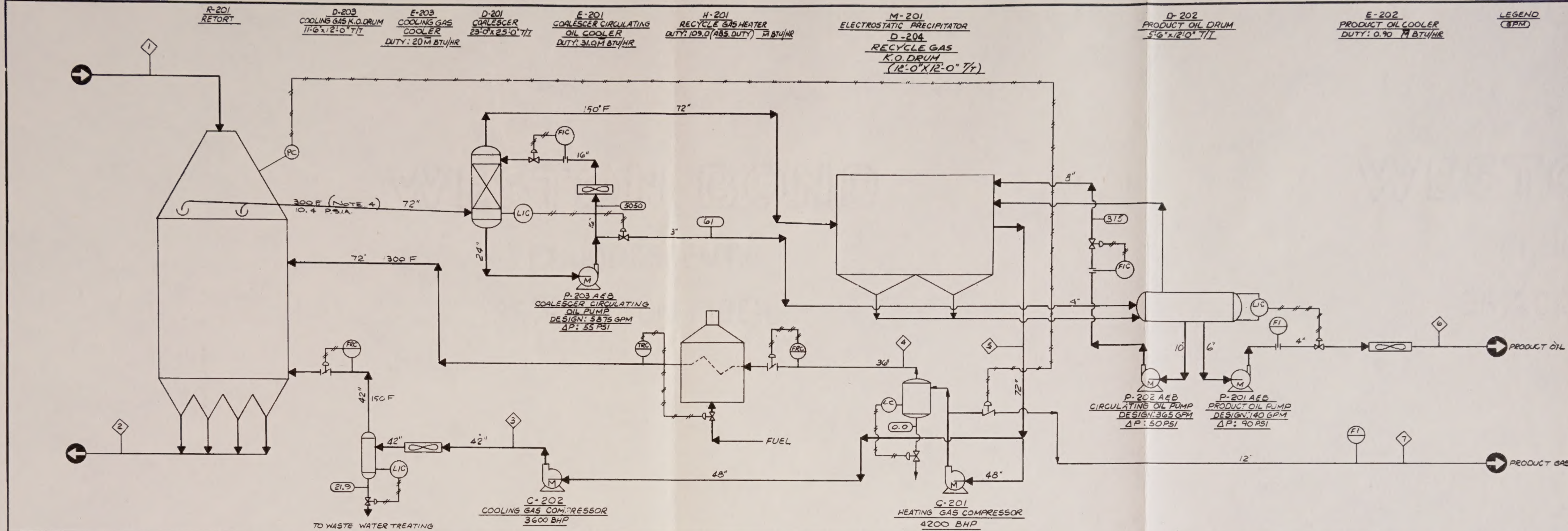
2) DESIGN BASIS FROM PARAHO AND DEI.
3) ALL RATES ARE FOR ONE RETORT.

CLIENT: PARAHO COMMERCIAL EVALUATION STUDY

TITLE: PARAHO DIRECT HEATED RETORT PROCESS FLOW DIAGRAM

McKee ENGINEERS AND CONSTRUCTORS CLEVELAND, OHIO

FIG. 4-11



STREAM NO. / STREAM NAME	1 RAW SHALE FEED	2 SPENT SHALE	3 COOLING GAS	4 HEATING RECYCLE GAS	5 PRECIPITATOR PRODUCT GAS	6 PRODUCT OIL	7 PRODUCT GAS
TEMPERATURE, °F	50.	310.	250	275	150.	120.	275
PRESSURE, PSIA	10.4	10.4	18.5	21.0	10.0	60.	18.0
SOLIDS							
LBS./HR.	546600	467682					
TONS/DAY	6559	5612					
GASES							
COMPOSITION MOL./HR.							
H_2			1504.1	1316.0	2907.8		87.7
N_2			31.1	27.2	60.1		1.8
CO			165.1	144.5	319.2		9.6
CO_2			913.6	799.4	1766.3		53.3
CH_4			1947.5	1704.1	3765.2		113.6
C_2H_4			759.8	664.8	1468.9		44.3
C_2H_6			273.1	239.0	528.0		15.9
C_3H_6			140.0	122.5	270.7		8.2
C_4H_{10}			40.6	35.5	78.5		2.4
LT. NAPHTHA (MW=100.0)			99.4	87.0	192.2		5.8
HVY NAPHTHA (MW=144.0)			49.3	43.1	95.3		2.9
H_2S			211.8	185.3	409.5		12.4
NH_3			79.5	69.6	153.7		4.6
H_2O			2428.9	2125.3	4695.9		141.7
TOTAL MOL./HR.			8643.8	7563.3	16711.3		504.2
LBS./HR.			187126	163733	361973		10915
$\overline{M}$ SCFH			3.276	2.866	6.333		0.191
M.W.			21.65	21.65	21.65		21.65
LIQUIDS							
BPSD						4167	
LBS/HR						57083	
API						19.1	
CS @ 100 °F						50.0	
CS @ 210 °F						5.8	
CS @ COND.						29.0	
WT % S						0.62	
WT % N_2						2.05	
POUR PT. °F						85	

NOTES:
1) DESIGN BASIS

RETORT THROUGH PUT	456 LB/HR/FT²
ACTIVE AREA	1200 FT²
FISHER ASSAY	29 GAL/T
OIL YIELD	92 % F.A.
PRODUCT GAS YIELD	700 SCF/T
HEATING RECYCLE GAS	10500 SCF/T
COOLING RECYCLE GAS	12000 SCF/T

2) DESIGN BASIS FROM PARAHO AND DEI.
3) ALL RATES ARE FOR ONE RETORT.
4) MIST CHARACTERIZATION DATA NOT AVAILABLE FOR INDIRECT MODE
5) RETORT ΔP 1.0" H_2O/FT

CLIENT: PARAHO COMMERCIAL EVALUATION STUDY

McKee ENGINEERS AND CONSTRUCTORS CLEVELAND, OHIO

TITLE: PARAHO INDIRECT HEATED RETORT PROCESS FLOW DIAGRAM

SCALE D.W. NO.

FIG. 4-12

REVISION

The module, or plant, would be considered successful if at the end of the first year:

The projected service factor is 90 percent or greater.

The throughput is greater than 90 percent of design.

The thermal efficiency, as measured by heat input, is no more than 10 percent greater than design.

The quality specifications are no more than 10 percent less than design.

The maximum diameter of the module was set at forty feet, because in McKee's opinion, this is the largest vessel that could be built using commercially available mill shapes and beams.

The scale up factor for both the 32 and 40 foot diameter retorts, 16 and 24, are well within those normally experienced by McKee in the development of ferrous and nonferrous pyro processes.

A forty foot diameter selection was justified on the overall development schedule as one which is subject to risks which are reasonable for a development project and the path which minimizes the overall project cost and time.

Paraho

TABLE NO. 4-12

DIRECT HEATED PROCESS
RETORT HEAT AND MASS BALANCE

IN:	Lbs/hr	MMBtu/hr
Raw Shale (50°F)	546,600	-3.06
Recycle Gas (225°F)	303,780	12.94
Air (175°F)	95,880	2.24
Combustion	---	128.7
	946,260	140.82

OUT:	Lbs/hr	MMBtu/hr
Offgas with oil (150°F)	508,380	11.31
Retorted Shale (380°F)	442,740	29.84
Water Vaporization	---	11.94
Carbonate Decomposition (27%)	---	33.69
Pyrolysis	---	22.48
Distributor Cooling	---	17.58
Skin Heat Loss & Unaccounted	-4,860	13.98
	946,260	140.82

Paraho

TABLE NO. 4-13

INDIRECT HEATED PROCESS

RETORT HEAT AND MASS BALANCE

IN:	Lbs/hr	MMBtu/hr
Raw Shale ($50^{\circ}F$)	546,600	-3.06
Hot Gas ($1300^{\circ}F$)	166,020	116.14
Bottom Cooling Gas ($150^{\circ}F$)	189,480	5.97
	902,100	119.05

OUT:	Lbs/hr	MMBtu/hr
Offgas with oil ($300^{\circ}F$)	423,360	43.51
Retorted Shale ($310^{\circ}F$)	472,260	24.46
Water Vaporization	---	11.94
Carbonate Decomposition (2.5%)	---	3.20
Pyrolysis	---	22.48
Skin Heat Loss & Unaccounted	6,480	13.46
	902,100	119.05

4.5 RETORTED SHALE MANAGEMENT

4.5.1 General

Retorted shale and rejected fine raw shale must be disposed of in an efficient manner. Surface disposal of all retorted shale and rejected fine raw shale has been selected for this project study. The environmental advantages of underground disposal are uncertain and not effectively demonstrated. Underground disposal would prevent secondary recovery of the oil shale in the pillars, back and floor of the mine. It is anticipated that a suitable technique for in situ retorting of this remaining resource will be developed during the 20-year plant life. The retorted shale disposal pile outlined in Figure 4-3 represents a 20-year disposal pile.

Volumes for this study were based on direct heated processes retorted shale. The retorted shale produced amounts to 82% of the raw shale retort feed on a weight basis. Rejected raw shale fines equal 5 weight% of the total shale mined and will be used for top dressing on the slopes, as well as fill material. Weight would increase by approximately 6% for retorted shale from the indirect heated process. Moisture addition may be required in order to control the greater dust potential and tendencies to self-ignite due to the higher quantity of active carbon on the surface.

4.5.2 Retorted Shale Handling

The retorted shale and rejected raw shale fines will be conveyed from the retorts to separate surge bins.

At full production, approximately 150,000 tons per day will be handled. Some of the rejected fines will be used to top dress the areas to be seeded in an effort to reduce surface temperatures and the remainder will be commingled with the cooled retorted shale unless some other beneficial use is available. Rejected fines will be used because the disposal site does not have an adequate source of soil for top dressing the areas to be vegetated.

The material will be hauled from the surge bins in 100 ton, bottom dump haulers to the disposal area. The hauler traffic will provide the primary compaction of the deposited material. To ensure structural integrity, the face area will be further compacted with conventional compactors. The dumps will be developed so that an average 4:1 slope is maintained. Each 40 foot lift will have a 40 foot wide berm for access and maintenance.

4.5.3 Water Quality and Vegetation

Water from normal run-off and leaching activities will be impounded in catchment basins. This water will be kept out of the regional drainage system. Evaporation and use for dust control will control the supply in the basins.

The areas to be vegetated will be surface leached with sprinklers prior to seeding. A heavy application of fertilizer will precede planting. A mixture of native grasses and shrubs will be seeded. The seeded areas will be irrigated and given supplemental applications of fertilizer for two growing seasons, after which that area will rely on natural precipitation for its water needs.

4.6 OFFSITE FACILITIES

The offsite facilities required are:

- Utilities
  - Raw water filtration
  - Boiler feed water treatment
  - Steam generation
  - Potable water treatment
  - Cooling tower
  - Electrical distribution
  - Plant air

  (Instrument Air is included with retorting and process units)

  These facilities would be sized to provide the requirements listed in the Utility Summary - Base Case - Table 4-14.
- Interconnecting Piping
- Relief and Blowdown System - Dual System
- Fire Water System
- Waste Water Treatment
- Sewers: Storm, Process, and Sanitary
- Solid Waste Treatment
- Administrative and Personnel Facilities
- Maintenance and Warehousing Facilities
- Control Laboratory
- Safety Facilities
- Roads
- Product Blending and Loading Facilities

The following are general statements concerning the most critical offsite facilities. Standard petroleum refinery practice will apply to the facilities not discussed.

TABLE 4-14
BASE CASE
UTILITY SUMMARY

	Power kw	Steam lbs/hr	Required Water, gpm	Available Water, gpm	Circulating Cooling Twr. (2) Water, gpm	Fuel BPSD, FOE	Diesel Fuel BPSD
MINING, CRUSHING AND SHALE DISPOSAL	77,500	-	1,257	-	-	-	830
RETORTING AND PRODUCT GAS PROCESSING	185,000	666,000	100	-	32,100	6,708	-
PROCESSING, OFFSITES AND AUXILIARIES	80,500	-	4,250	950	63,200	14,897	-
SUBTOTAL	343,000	666,000	5,607	950	95,300	21,605	830
POWER PLANT	(343,000)	-	345	-	-	17,409	-
TOTAL	-	666,000	5,952	950 (1)	95,300	39,014	830

NOTES:

1) Cooling tower blowdown available for dust control.

2) 30 F ΔT

4.6.1 Water

All water systems and consumptions have been carefully reviewed to minimize the amount of raw make-up water that will be required from the Colorado River.

The estimated make-up water quantities for the studied cases are:

	GPM	Acre-ft/yr	Cu. ft/sec
Base Case	5002	8,070	11.1
Alternate 1	5152	8,310	11.5
Alternate 2A	3557	5,740	7.9
Alternate 2B	2147	3,460	4.8
Alternate 2C	3182	5,130	7.1

(No water sources have been considered as being available from the mining operation).

The raw water supply system shall consist of a water intake, primary setting, and pumping facilities located at the Colorado River immediately south of Anvil Points.

On site water facilities will include an intermediate storage pond, raw water filtration, demineralized boiler feed water treatment, and potable water treatment.

4.6.2 Product Pipelines

Product pipelines have not been included in the cases studies but are pertinent to a shale oil project. The following information would relate to product lines from this shale oil complex:

A shale oil product pipeline is feasible to existing crude pipeline terminal facilities located at Casper, Wyoming, a distance of 290 miles away. It is estimated that the installation cost would be about $75,000,000 plus appropriate owner's preoperation project costs.

A possible gas pipeline connection (not studied) is in the Rangely, Colorado area. A 75 mile line would be required, and the estimated installation cost is about $13,000,000 plus appropriate owner's preoperation project costs.

4.6.3 Electric Power Plant

It has been assumed that a contiguous electric power generation plant would be built and operated by others. It would be sized to provide the shale oil complex requirements only, except for the all Direct Heated Retorts case where surplus low Btu gas would be used to generate export power. Capital construction costs for the electric power plants in the various cases are budget estimated as follows:

Base Case:	$151 MM
Alternate 1:	$157 MM
Alternate 2A:	$166 MM
Alternate 2B:	$108 MM
Alternate 2C:	$131 MM

4.6.4 Waste Treatment

All waste systems will be designed and operated to protect the existing ecology and meet all environmental regulations.

4.7 UPGRADING

Crude shale oil from the retorting operation contains sulfur, nitrogen, and oxygen in amounts that restrict its use as a refinery feedstock. The petroleum industry, however, has technology which is adaptable for upgrading the crude shale oil to refined products.

The processing of crude shale oil is directed towards reduction of sulfur, nitrogen, and oxygen to product specification levels with proper attention to carbon/hydrogen ratios and the myriad of additional physical and chemical properties which deal with product usage. The processing of crude shale oil can be done at or near the mining/retorting site or at a refining site. The processing at the mining/retorting site can be directed towards meeting final product specifications or a somewhat reduced scope and severity sufficient to enable the upgraded shale oil to be used as a crude oil supplement in "normal" refinery operations. Crude shale oil has a pour point in the 50°F - 85°F range depending on retort operating conditions. Movement in a pipeline requires the addition of pour point depressant. If upgrading processing is conducted at the retort site the pour point of the liquid product is reduced sufficiently to allow pipeline movement without pour depressant.

Typical crude shale oil property values which were determined from Paraho produced oil are:

	D.H. Retort	I.H. Retort
Gravity, °API	21.2	19.1
Pour Point, °F	80	85
Nitrogen, Wt.%	1.90	2.05
Sulfur, Wt.%	.63	.62
Oxygen, Wt.%	1.24	1.28
C:H Ratio	7.20	7.34

(For details see Appendix)

Two upgrading cases were evaluated for this study:

Base Case: Coking followed by liquid hydrotreating.
Alternate 1: Direct hydrotreating of crude shale oil.

Three additional cases in which no upgrading was included were also studied:

Alternate 2A: All DH Retorts
Alternate 2B: All IH Retorts
Alternate 2C: 18/6 DH/IH Retorts with IH Retort Gas to SNG

4.7.1 Base Case Upgrading

The base case upgrading scheme (coking followed by liquid hydrotreating) involves less technical risk. The coking operation encompasses (1) fractionation of the crude shale oil, (2) coking of recycle plus atmospheric tower bottoms, and (3) fractionation of coking liquid-gas products.

The coker operation produces three liquid streams (naphtha, light gas oil, and heavy gas oil). These streams are processed individually in hydrotreaters. The gas streams, from the hydrotreaters contain both H_2S and ammonia in recoverable quantities.

Coker sour water and hydrotreater wash water are fed to a Chevron Waste Water Treating Unit for ammonia recovery and H_2S separation. The gas streams, after water washing for ammonia removal, are amine treated. The H_2S from the amine units and the WWT unit is fed to a sulfur plant. Tail gas is processed in the Stretford Unit.

4.7.2 Alternate 1 Upgrading

The assumption that crude shale oil can be fed to a hydrotreater (Alt. 1) has some technical risk. Catalyst life and space velocity considerations may make this case infeasible. Hydrogen consumption is not expected to be appreciably different from the coker case since the feed C/H ratios are not greatly different. The direct hydrotreating case is similar to the base case (coking - hydrotreating). The utilization of energy sources and elimination of the coking operation are the major differences.

4.7.3 Process Unit Requirements

Major process units for the two cases are:

	Base Case	Alt. 1
Cokers	2	-
Hydrogen Plants	2	2
Crude Shale Hydrotreaters	-	2
Coker Product Hydrotreaters	3	-
Naphtha Hydrotreater	-	1

The support facilities for sour water processing and sulfur removal are similar to the base case.

Block flow diagrams for the five cases are given in Figures 4-13, 4-14, 4-15, 4-16, and 4-17.

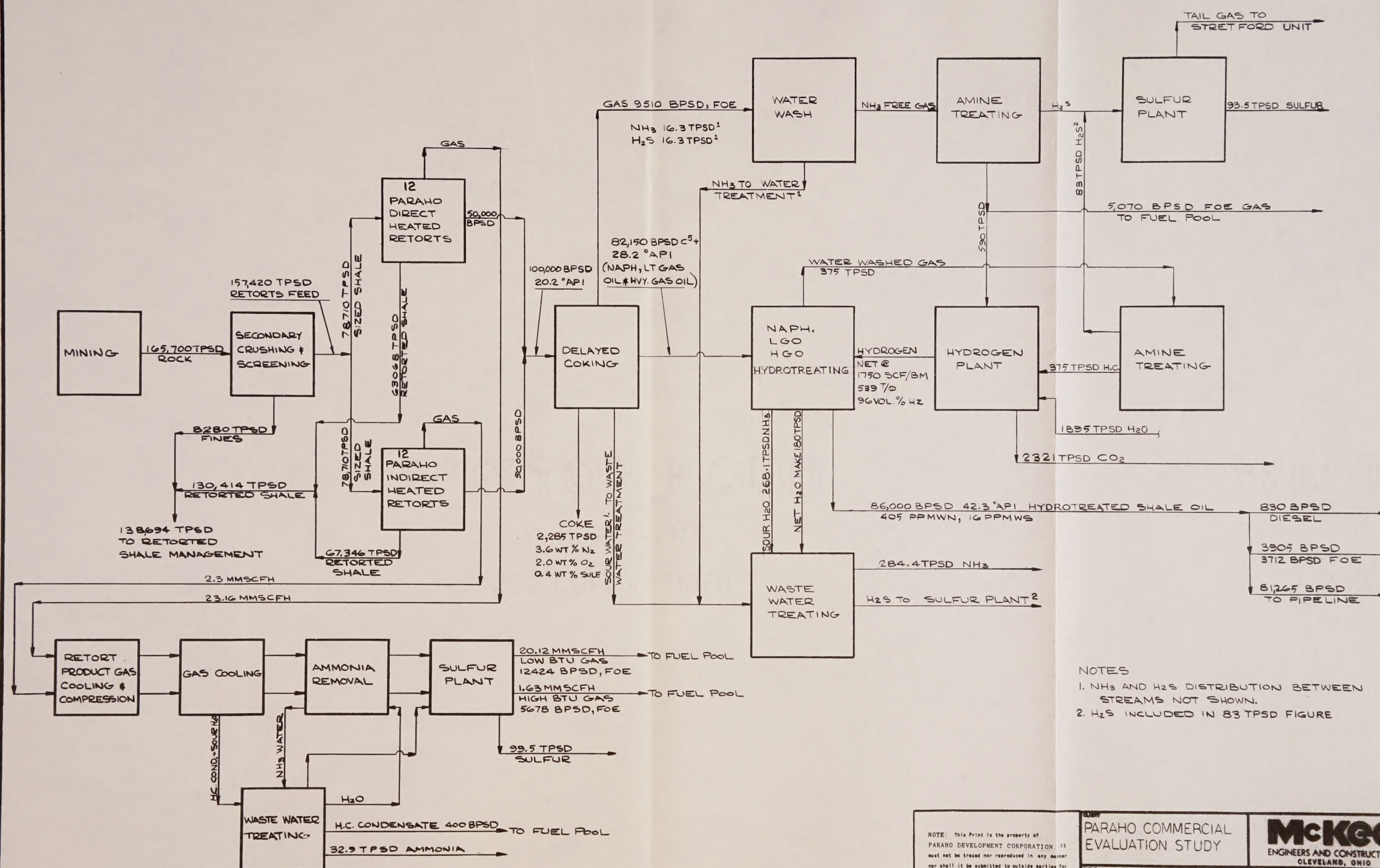
4.7.4 Product Specifications

The degree of sulfur and nitrogen removal in the hydrotreating operation is affected by coking the crude shale oil.

The extent of sulfur and nitrogen remaining in the two cases is shown below in parts per million by weight.

	Vol.%	PPMWN	PPMWS	Pour ^{O}F	^{O}API
Base Case					
Coking - H_2 Treat					
Naphtha	24.0	1	1	-60	58
400-600^{O}F Diesel	45.0	200	20	20	40
600^{O}F + BTMS.	31.0	1000	20	20	35
TOTAL	100.0	405	16	15	42.3
Alternate 1					
H_2 Treating					
Naphtha	25.0	1	-	-60	58
400-600^{O}F Diesel	30.0	200	50	0	39
600^{O}F + BTMS.	45.0	600	400	100	32
TOTAL	100.0	320	210	50	40.0

The upgraded shale oil is suitable as a refinery feedstock. The absence of 900^{O}F plus material will be particularly advantageous to refiners that have problems with "bottom of the barrel" processing.



NOTES

1. NH_3 AND H_2S DISTRIBUTION BETWEEN STREAMS NOT SHOWN.
2. H_2S INCLUDED IN 83 TPSD FIGURE

CLIENT: PARAHO COMMERCIAL EVALUATION STUDY

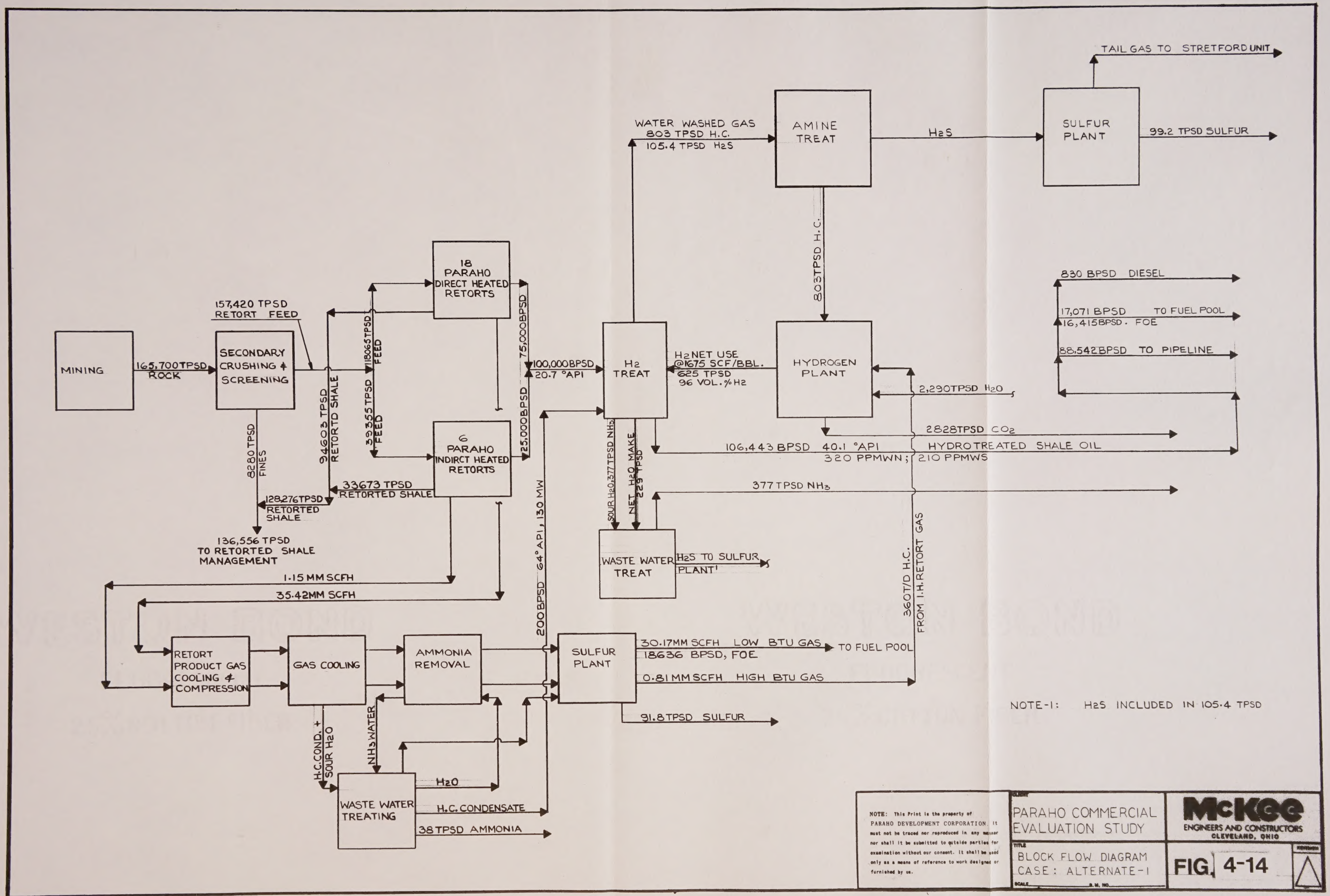
TITLE: BLOCK FLOW DIAGRAM BASE CASE

SCALE ________ B.M. NO. ________

McKee ENGINEERS AND CONSTRUCTORS CLEVELAND, OHIO

FIG. 4-13

REVISION △



MINING
165,700 TPSD ROCK
SECONDARY CRUSHING & SCREENING
157,420 TPSD RETORT FEED
8280 TPSD FINES
94603 TPSD RETORTD SHALE
118065 TPSD FEED
39355 TPSD FEED
18 PARAHO DIRECT HEATED RETORTS
6 PARAHO INDIRCT HEATED RETORTS
75,000 BPSD
25,000 BPSD
100,000 BPSD 20.7 °API
33673 TPSD RETORTED SHALE
128,276 TPSD RETORTED SHALE
136,556 TPSD TO RETORTED SHALE MANAGEMENT
1.15 MM SCFH
35.42 MM SCFH
200 BPSD 64° API, 130 MW
H2 TREAT
WATER WASHED GAS 803 TPSD H.C. 105.4 TPSD H2S
AMINE TREAT
H2S
SULFUR PLANT
TAIL GAS TO STRETFORD UNIT
99.2 TPSD SULFUR
803 TPSD H.C.
H2 NET USE @1675 SCF/BBL. 625 TPSD 96 VOL.% H2
HYDROGEN PLANT
2,290 TPSD H2O
2828 TPSD CO2
106,443 BPSD 40.1 °API HYDROTREATED SHALE OIL 320 PPMWN; 210 PPMWS
377 TPSD NH3
SOUR H2O; 377 TPSD NH3
NET H2O MAKE 229 TPSD
WASTE WATER TREAT
H2S TO SULFUR PLANT[1]
360 T/D H.C. FROM I.H. RETORT GAS
830 BPSD DIESEL
17,071 BPSD TO FUEL POOL
16,415 BPSD. FOE
88,542 BPSD TO PIPELINE
RETORT PRODUCT GAS COOLING & COMPRESSION
GAS COOLING
AMMONIA REMOVAL
SULFUR PLANT
30.17 MM SCFH LOW BTU GAS
18636 BPSD, FOE
TO FUEL POOL
0.81 MM SCFH HIGH BTU GAS
91.8 TPSD SULFUR
H.C. COND. + SOUR H2O
NH3 WATER
WASTE WATER TREATING
H2O
H.C. CONDENSATE
38 TPSD AMMONIA
NOTE-1: H2S INCLUDED IN 105.4 TPSD
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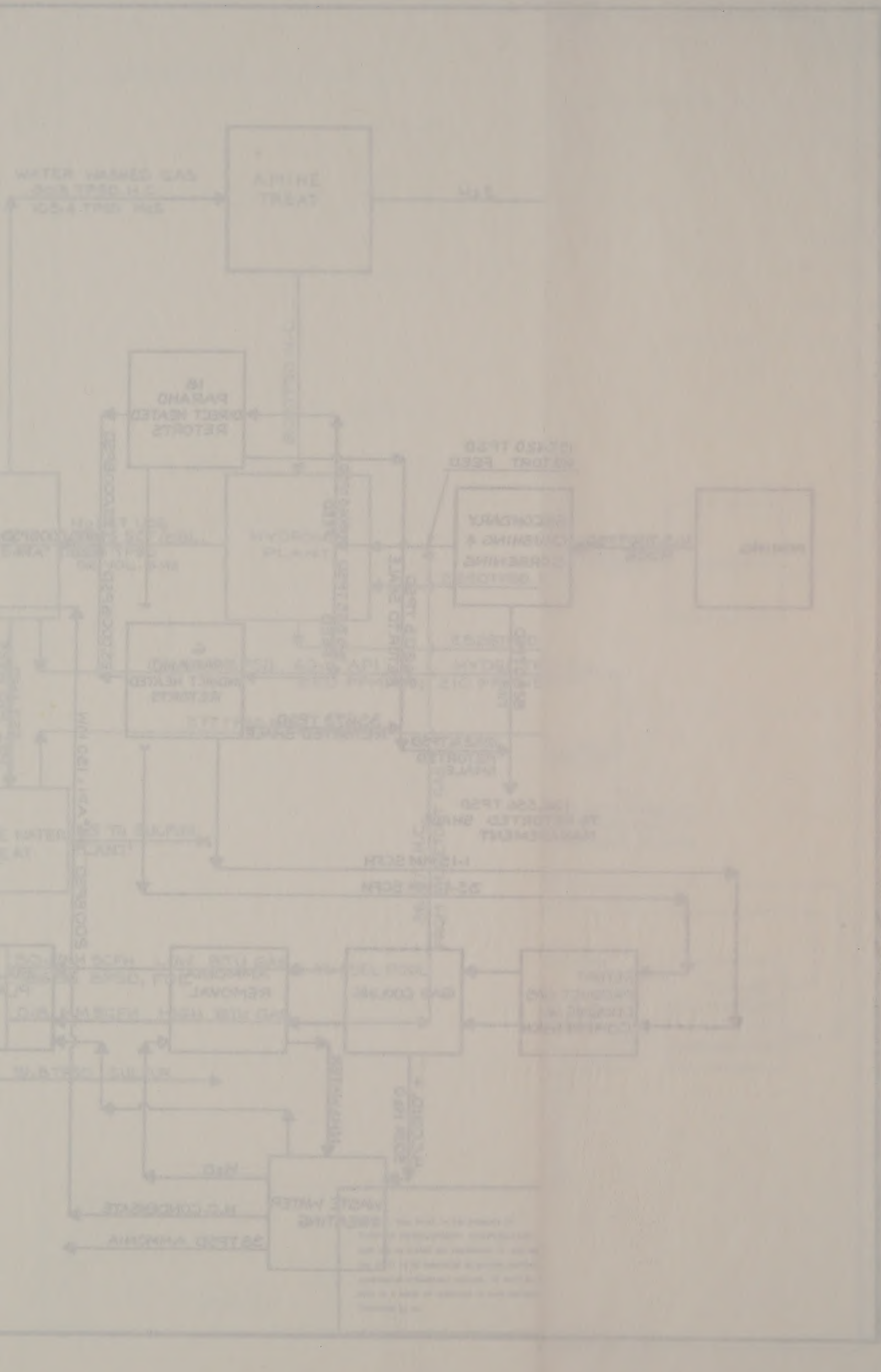
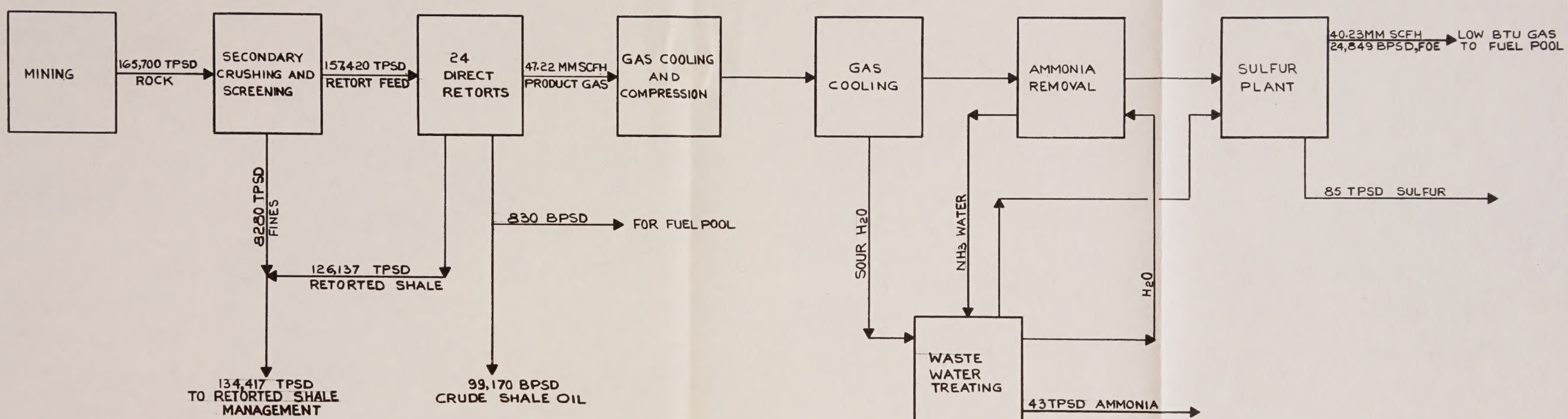
PARAHO COMMERCIAL EVALUATION STUDY
BLOCK FLOW DIAGRAM CASE: ALTERNATE-1
McKee ENGINEERS AND CONSTRUCTORS CLEVELAND, OHIO

FIG. 4-14





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CLIENT: PARAHO COMMERCIAL EVALUATION STUDY

TITLE: BLOCK FLOW DIAGRAM CASE: ALTERNATE-2A

SCALE | D. W. NO.

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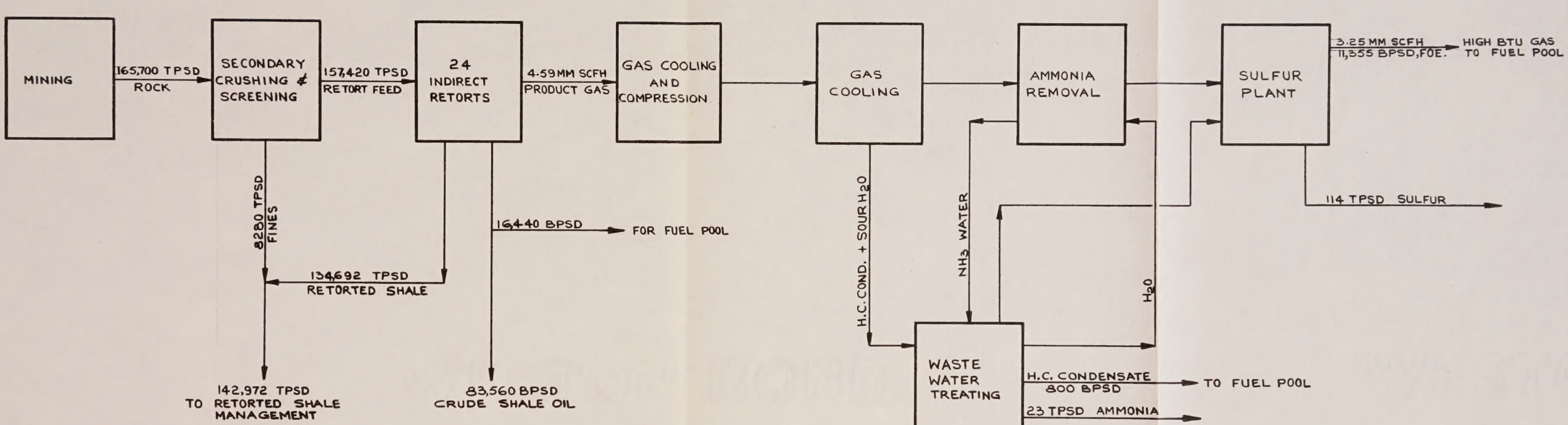
FIG 4-15

REVISION



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CLIENT: PARAHO COMMERCIAL EVALUATION STUDY

TITLE: BLOCK FLOW DIAGRAM
CASE: ALTERNATE-2B

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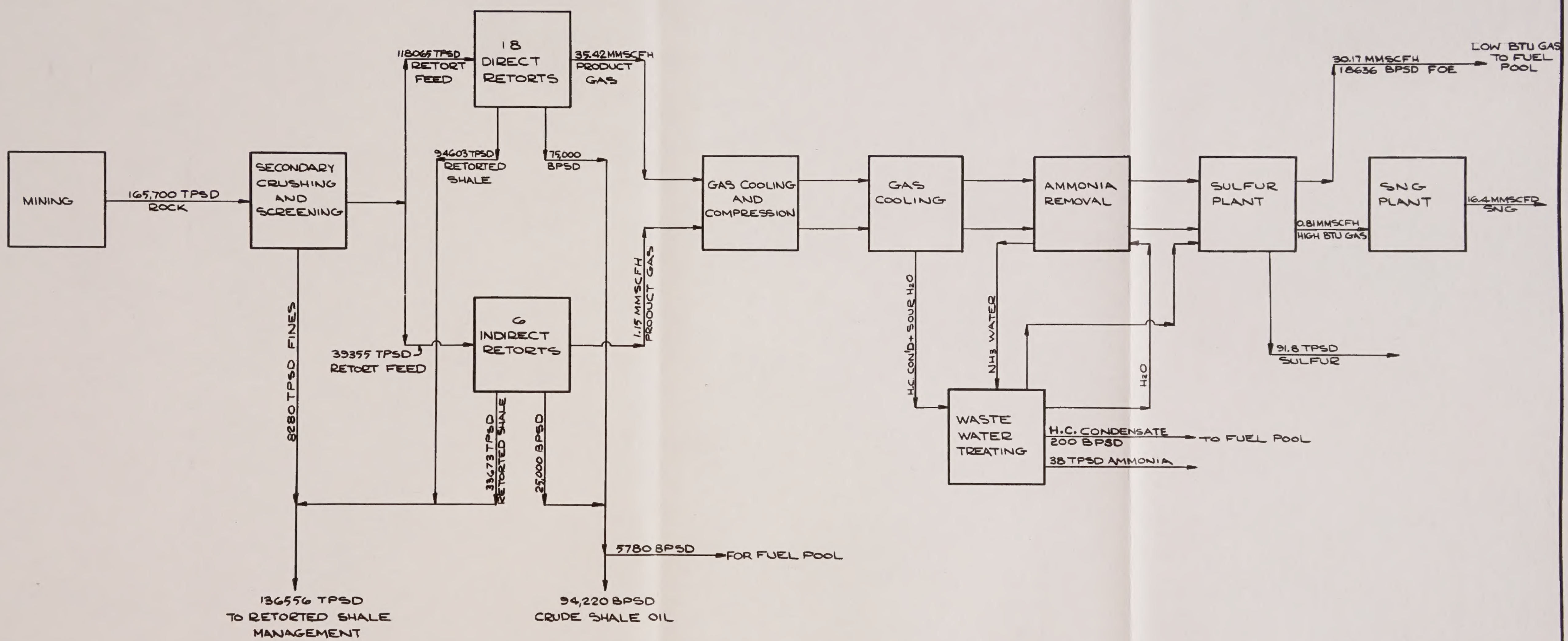
FIG. 4-16



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CLIENT: PARAHO COMMERCIAL EVALUATION STUDY

TITLE: BLOCK FLOW DIAGRAM CASE: ALTERNATE 2C

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FIG 4-17

5. APPENDIX

SOHIO PETROLEUM COMPANY

DEVELOPMENT TECHNICAL RESPONSE NO. 171

Copies: S. K. Kunchal, E. K. Frazier, R. F. Faubus (2), J. C. Jansma, J. L. Petersen (3), J. E. Metcalfe, Library

Title: Limited Assay of Crude Shale Oil Produced by Direct Heat Retorting

Project: 2330-02 Requested by S. K. Kunchal

Date: 5/19/76 Author: H. E. Alford

OBJECTIVE:

Conduct a limited assay of crude Shale Oil produced by Direct Heat Retorting. The oil received was labled drum 174 and was collected from tank number 520 on November 29, 1975. It was from Semi-Works Retort Run Number SW-20.

Crude Received:	2/8/76
Partial Assay:	4/1/76
Preliminary Assay: (missing PNA & O_2 data)	4/15/76
Final Limited Assay:	5/19/76

CONCLUSIONS:

There was a considerable amount of water in the sample that caused some difficulty in sampling. The amount of water was not measured.

With some changes made on the mass spectrometer, we were able to obtain hydrocarbon type analyses on all fractions. The crude produced by direct heat retorting is more aromatic and the light fractions are more olefinic than that produced in the indirect heat mode. It is also more aromatic than the shale oil sampled last year (TR #4800, 5/28/75).

Metals were done by atomic adsorption spectroscopy. The results agree well with those obtained last year. The manner of retorting apparently has little effect.

HE Alford

Although crude shale oil produced by direct heat retorting did not form any gas on distillation, it did produce more liquid boiling below 380°F. than that produced by indirect heat retorting or that assayed in 1975.

As before, the nitrogen content was high, and in general, increases with boiling point. Sulfur content decreases with boiling point. The nitrogen content of this crude was slightly lower than that produced by indirect heat retorting.

The elemental analysis balances were good. Oxygen analyses were done by neutron activation.

All of the fractions were highly colored. The color appeared to deepen on standing.

DISCUSSION:

This assay was patterned after the one run a year ago (TR #4800, 5/28/75). It does not include all of the inspections normally obtained in a crude assay. This is by necessity in the case of the naphtha cuts, since only a small amount of light distillate was obtained. It does include an elemental analysis on each of the fractions.

This particular sample of crude shale oil gave us some problems in sampling because of water. We did not determine the water content; Paraho's analysis shows 11.91%. Because of the viscosity and gravity of the crude, this did not settle. Rather, it stayed in pockets and layers in the drum. By sampling carefully, we did obtain enough water-free material for distillation.

With our revamped mass spectrometer, combined with FIA or elution analysis, we were able to obtain hydrocarbon type analysis on all fractions. In addition to reporting the totals, we have also shown a breakdown of the hydrocarbons in each fraction. Naphthene content is reasonably constant over the entire boiling range; aromatics increase with boiling point. Olefins presented a unique problem in FIA separation; they did not fluoresce as they were supposed to. NMR analysis confirmed that the entire non-fluorescent band was olefinic. We believe the values to be correct. The cumulative totals have been plotted.

Originally, oxygen determinations were made using our Perkin-Elmer Model 240 Elemental Analyzer. These values were reported in the Partial Assay of the crude. We then discovered that we were getting interference, probably from sulfur compounds, using this technique. Consequently, oxygen determinations were repeated, using neutron activation. These values are reported in this assay.

HE Alford

HEA/vlm
5/20/76

HEA/vlm
2/11/76

SOHIO PETROLEUM COMPANY

DTR #171
5/19/76 HEA

CRUDE ASSAY

CRUDE Paraho Shale Oil - Direct Heat Retorting

C.O.P. No. --- TS No. 76-5200-5 Work Requested by S. K. Kunchal
Sample Received 2/8/76 Sample Collected
Source of Sample Paraho Oil Shale Demonstration, Inc.

Table 1 - Properties of Settled Crude

Gravity, °API	21.2	Total Sulfur, Wt. %	0.63
Specific Gravity @ 60°F	0.9267	Total Nitrogen, Wt. %	1.90
Pour Point, °F	80	RVP, lb.	---
Viscosity, SSU		Total Acid No., mg. KOH/gm	1.62
@ 60°F	Too Heavy	Asphaltenes, Wt.% (STM-31)	1.094
@ 100°F	162.9	Ramsbottom Carbon, Wt. %	1.585
VGC	0.8873		

BS & W, Vol. %	0.14	(0.27, vol.% as received unsettled)
Salt, lb./M Bbls.	0.396	(0.428, lb./M Bbls. as received unsettled)

Metals, ppm (AA)
As 20 Ni 2.3
Fe 35.8 V 0.25

Vis. @ 140°F. SSU 71.0
Vis. @ 210°F. SSU 41.3

Carbon, Wt. % 84.20
Hydrogen, Wt. % 11.69
Oxygen, Wt. % 1.24

Corrosive Sulfur

Temperature, °F.	Corrosive Sulfur, ppm Hydrogen Sulfide-S	Mercaptan-S	Total
Ambient	---	---	---
Initial- 200	0.5	---	0.5
201 - 300	3.4	---	3.4
301 - 400	26.4	---	26.4
401 - 500	32.9	0.3	33.2
501 - 600	63.6	11.0	74.6
601 - 700	75.8	28.8	104.6
701 - 750	210.2	24.9	235.1
Purge	14.8	7.7	22.5
Total	427.6	72.7	500.3
Total, #/M bbls.	139	24	163

Table 2 - Hempel Distillation (D-285) of Crude

IBP	186
Vol. % Rec. at 95°F	
125°F	
165°F	
200°F	0.3
250°F	0.7
300°F	1.3
350°F	3.0
400°F	7.0
450°F	12.5
500°F	18.7
Weight of 500+ Residue	230.3
Volume of Residue	243.0
Vol. % Residue	81.0
Vol. % Loss	0.3

Inspections on Residue (500+)

Specific Gravity @ 60°F	0.9478
Gravity, °API	17.8
Vix. SSU @ 140°F.	218
Vis. SSU @ 210°F	62.1
Car. Res., Ramsbottom, wt. %	2.822
Sulfur in Coke, Wt. %	

Approximate Composition, Vol. %

C_5 & Ltr. (evap. @ 125)	0
125°-400° Naphtha	7.3
400°-500° Kerosine	11.7
Gas Oil (Res.-Asph.)	66.1
Asphalt (Calc.)	14.9
Asphalt Quality "A"	0.9152

DTR #171
5/19/76 HEA

SOHIO PETROLEUM COMPANY

Table 3

Crude Shale Oil - Direct Heat Retorting C.O.P. Number

TBP Distillation of Crude

Cut	°API	Sp. Gr.	Wt. %		Vol. %		Cum. Vol. %
Gas							
55-165							
165-220	52.9	0.7674	0.55		0.66		0.66
220-280	50.5	0.7775	0.10		0.12		0.78
280-340	45.7	0.7985	1.83		2.12		2.90
340-380	39.2	0.8289	1.96		2.19		5.09
380-480	36.1	0.8443	5.95		6.53		11.62
480-520	30.8	0.8718	4.34		4.61		16.23
520-600	28.3	0.8855	6.87		7.19		23.42
600-650	24.6	0.9065	5.53		5.65		29.07
650-700	21.9	0.9224	5.80		5.83		34.90
700-750	20.8	0.9291	5.70		5.69		40.59
750-800	20.6	0.9303	5.48		5.46		46.05
800-850	19.4	0.9377	6.03		5.96		52.01
850-900	16.3	0.9574	16.60		16.07		68.08
900 -Btms.	10.9	0.9937	32.45	33.26*	30.26	31.92*	100.00
Loss			0.81	0	1.66	0	
Total			100.00	100.00	100.00	100.00	

*Corrected for Loss

HEA/vlm
2/11/76

DTR #171
5/19/76 HEA

CRUDE ASSAY - TABLE 4

HYDROCARBON TYPE ANALYSIS BY MS

Crude: Shale Oil - Direct Heat Retorting

		Vol. %							
Cut Temperature, °F.		165-220	220-280	280-340	340-380	380-480	480-520		
Paraffins		26.8	20.3	41.0	40.7	37.3	39.4		
Cycloparaffins									
1 Ring		8.9	8.8	11.0	17.4	15.4	12.8		
2 Ring		0.4	2.0	6.4	7.9	17.5	14.9		
3 Ring									
4 Ring									
5 Ring									
6 Ring									
Total Cycloparaffins		9.3	10.8	17.4	25.3	32.9	27.7		
Aromatics									
Alkyl Benzenes		20.8	23.3	18.0	16.1	7.9	6.3		
Naphthene Benzenes		0.3	0.3	0.6	1.9	9.2	9.1		
Dinaphthene Benzenes									
Naphthalenes			0.1	0.5	0.1	2.1	7.7		
Acenaphthenes, Biphenyls						0.6	1.9		
Acanaphthalenes, Fluorenes						1.6	2.7		
Phenanthrenes, Anthracenes									
Naphthene Phenanthrenes									
Pyrenes									
Chrysenes									
Perylenes									
Dibenzo Anthracenes									
Benzothiophenes						1.6	3.0		
Dibenzothiophenes									
Naphthobenzothiophenes									
Total Aromatics		21.1	23.7	19.1	18.1	23.0	30.7		
Olefins		42.8	45.2	22.5	15.9	6.8	2.2		

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2/11/76

DTR #171
5/19/76 HEA

CRUDE ASSAY - TABLE 4

HYDROCARBON TYPE ANALYSIS BY MS

Crude: Shale Oil - Direct Heat Retorting

	Wt. %							
Cut Temperature, °F.	520-600	600-650	650-700	700-750	750-800	800-850	850-900	900+
Paraffins	27.4	21.0	20.6	9.4	15.3	5.6	3.1	Ins. Sample
Cycloparaffins								
1 Ring	11.1	10.1	8.3	5.9	7.2	4.9	1.3	
2 Ring	3.1	2.9	2.1	3.2	2.4	8.2	1.6	
3 Ring	1.7	1.6	0.7	3.5	2.2	7.1	7.9	
4 Ring	0.8	0.6		3.4	1.1	4.3	7.8	
5 Ring			0.1	2.6	0.3	1.4	2.0	
6 Ring					0.2	0.9	1.8	
Total Cycloparaffins	16.7	15.2	11.2	18.6	13.4	26.8	22.4	
Aromatics								
Alkyl Benzenes	14.1	15.6	18.1	14.5	20.9	19.3	12.3	29.2
Naphthene Benzenes	11.9	12.0	11.1	8.7	8.8	9.3	8.9	12.8
Dinaphthene Benzenes	9.7	11.5	7.0	11.8	10.8	10.6	11.7	14.6
Naphthalenes	12.4	10.6	9.9	8.7	7.1	7.1	8.4	12.7
Acenaphthenes, Biphenyls	3.0	5.9	7.6	9.1	6.5	5.7	8.4	9.6
Acanaphthalenes, Fluorenes	2.1	4.8	9.7	8.8	6.6	5.4	8.5	8.6
Phenanthrenes, Anthracenes	1.4	2.9	4.0	5.8	5.4	4.6	7.3	5.4
Naphthene Phenanthrenes			0.8	1.2	1.6	1.7	2.9	0.6
Pyrenes		0.1		1.1	1.7	1.8	2.9	0.5
Chrysenes				0.3	0.2	0.5	1.3	0.1
Perylenes							0.1	
Dibenzo Anthracenes								
Benzothiophenes	1.3	0.4		1.7	1.4	1.3	1.0	1.1
Dibenzothiophenes				0.3	0.2	0.2	0.7	1.0
Naphthobenzothiophenes					0.1	0.1	0.1	
Total Aromatics	55.9	63.8	68.2	72.0	71.3	67.6	74.5	96.2

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2/11/76

TABLE 5

PROPERTIES OF NAPHTHAS

	165-220	220-280	280-340	340-380
Cum. Mid Vol. %	0.33	0.72	1.84	4.00
Vol. % of Crude	0.66	0.12	2.12	2.19
Cum. Vol. % of Crude	0.66	0.78	2.90	5.09
Gravity, °API	52.9	50.5	45.7	39.2
Specific Gravity @ 60°F.	0.7674	0.7775	0.7985	0.8289
ASTM Dist., D-86, °F.				
IBP	Ins. Samp.	Ins. Samp.	260	300
@ 10% Evap.			297	330
@ 30% Evap.			311	345
@ 50% Evap.			314	356
@ 70% Evap.			318	361
@ 90% Evap.			330	370
EP			354	387
% Rec.			99	99
% Res.			1	1
Total Sulfur, ppm	1.02	1.13	0.96	0.83
Mercaptan Sulfur, Wt.%	xxxx	xxxx	xxxx	102
Total Nitrogen, Wt.%	0.05	0.14	0.74	1.23
UOP "K" Factor	xxxx	xxxx	11.50	11.27
Aniline Point, °F.	xxxx	xxxx	xxxx	85
Cetane Index	xxxx	xxxx	xxxx	287
Smoke Point, mm	xxxx	xxxx	xxxx	16
Pout Point, °F.	xxxx	xxxx	xxxx	fl. @ -50
Freezing Point, °F.	xxxx	xxxx	xxxx	too dark
Paraffins, Vol. %	26.8	20.3	41.0	40.7
Naphthenes, Vol. %	9.3	10.8	17.4	25.3
Aromatics, Vol. %	21.1	23.7	19.1	18.1
Olefins, Vol. %	42.8	45.2	22.5	15.9

DTR #171
5/19/76 HEA

TABLE 6

PROPERTIES OF MIDDLE DISTILLATES

	380-480	480-520	520-600	600-650
Cum. Mid Vol. %	8.36	13.93	19.83	26.25
Volume % of Crude	6.53	4.61	7.19	5.65
Cum. Vol. % of Crude	11.62	16.23	23.42	29.07
Gravity, °API	36.1	30.8	28.3	24.6
Specific Gravity @ 60°F.	0.8443	0.8718	0.8855	0.9065
ASTM Dist., D-86, °F.				
IBP	394	460	442	480
@ 10% Evap.	408	480	530	595
@ 30% Evap.	420	492	540	605
@ 50% Evap.	422	498	542	613
@ 70% Evap.	426	504	550	620
@ 90% Evap.	443	517	561	635
EP	462	557	580	660
% Rec.	99	99	99	99
% Res.	1	1	1	1
Vanadium, ppm	xxxx	xxxx	< 0.01	< 0.01
Nickel, ppm	xxxx	xxxx	0.18	0.24
Iron, ppm	xxxx	xxxx	5.4	3.2
Viscosity, CS/100°F.	xxxx	xxxx	5.66	10.17
Viscosity, SSU/100°F.	xxxx	xxxx	44.5	59.4
Viscosity, CS/210°F.	xxxx	xxxx	1.63	2.23
Viscosity, SSU/210°F.	xxxx	xxxx	31.5	33.6
Total Sulfur, Wt.%	0.74	0.82	0.69	0.74
Mercaptan Sulfur, ppm	56.4	60.7	37.9	28.8
Total Nitrogen, Wt. %	0.96	1.27	1.72	1.75
UOP "K" Factor	11.36	11.31	11.30	11.29
Paraffins, Volume %	37.3	39.4	27.4*	21.0*
Naphthenes, Volume %	32.9	27.7	16.7*	15.2*
Aromatics, Volume %	23.0	30.7	55.9*	63.8*
Olefins, Volume %	6.8	2.2	----	----
Aniline Point, °F.	98	99	112	97
Pour Point, °F.	-45	-20	15	35
Freezing Point, °F.	Too dark	too dark	xxxx	xxxx
Thermo Vis. @ 60°F.	too dark	too dark	xxxx	xxxx
Ring Number	too dark	too dark	xxxx	xxxx
Cetane Index	36.5	38.5	40.0	41.9
Smoke Point, mm	15	12	xxxx	xxxx
Diesel Index	35.3	30.4	31.7	23.9
T. Acid No., mg KOH/g.	xxxx	xxxx	1.341	0.790
R. I. @ 140°F.	xxxx	xxxx	too dark	too dark

*Wt.%

DTR #171
5/19/76 HEA

TABLE 7

PROPERTIES OF THE HEAVY DISTILLATES

	650-700	700-750	750-800	800-850	850-900
Cum. Mid Volume %	31.99	37.75	43.32	49.03	60.05
Volume % of Crude	5.83	5.69	5.46	5.96	16.07
Cum. Volume % of Crude	34.90	40.59	46.05	52.01	68.08
Gravity, °API	21.9	20.8	20.6	19.4	16.3
Specific Gravity @ 60°F.	0.9224	0.9291	0.9303	0.9377	0.9574
ASTM Dist., D-1160, °F.					
IBP	625	696	732	773	735
@ 10% Evap.	646	713	756	806	821
@ 30% Evap.	649	721	765	817	847
@ 50% Evap.	652	726	771	822	857
@ 70% Evap.	659	730	778	831	871
@ 90% Evap.	668	737	788	847	894
EP	684	755	812	888	915
% Rec.	98	98	98	98	97
% Res.	2	2	2	2	3
Vanadium, ppm	<0.01	0.01	0.01	0.01	0.05
Nickel, ppm	0.12	0.20	0.31	0.44	0.65
Iron, ppm	3.7	11.3	11.6	13.3	29.5
Viscosity, CS/100°F.	20.60	41.28	70.82	38.82*	87.06*
Viscosity, SSU/100°F.	100.4	192.6	328.5	xxxx	xxxx
Viscosity, CS/210°F.	3.29	4.76	6.50	9.31	15.87
Viscosity, SSU/210°F.	37.1	41.9	47.5	56.8	81.4
Total Sulfur, Wt.%	0.69	0.61	0.58	0.54	0.57
Mercaptan Sulfur, ppm	45.2	70.1	62.7	48.4	60.9
Total Nitrogen, Wt.%	2.02	2.08	2.01	1.74	1.84
UOP "K" Factor	11.23	11.39	11.52	11.59	11.45
Paraffins, Wt. %	20.6	9.4	15.3	5.6	3.1
Naphthenes, Wt. %	11.2	18.6	13.4	26.8	22.4
Aromatics, Wt.%	68.2	72.0	71.3	67.6	74.5
Aniline Point, °F.	106	107	114	128	129
Pour Point, °F.	60	75	90	105	105
Cetane Index	41.4	47.4	51.6	54.2	51.2
T. Acid No., mg KOH/g.	0.488	0.803	0.309	0.112	0.279
R. I. @ 140°F.	too dark	too dark	too dark	too dark	too dark

*Vis. @ 140°F.

DTR #171
5/19/76 HEA

TABLE 8

PROPERTIES OF THE RESIDUE

	900+
Volume % of Crude	31.92
Cum. Vol.% of Crude	100.00
Gravity, °API	10.9
Specific Gravity @ 60°F.	0.9937
Abs. Vis. @ 140°F., Poises	22.1
Kin. Vis. @ 140°F., CS	2292
Kin. Vis. @ 210°F., CS	154.4
Vis. @ 210°F., SSU	720
Kin. Vis. @ 275°F., CS	34.3
Furol Vis., @ 275°F., SSF	16.3
Total Sulfur, Wt. %	0.54
Total Nitrogen, Wt. %	2.42
Vanadium, ppm	1.0
Nickel, ppm	8.7
Iron, ppm	126
Insolubles in Pentane, Wt. %	7.44
Paraffins, Wt. % Naphthenes, Wt. %	3.8
Aromatics, Wt. %	96.2

DTR #171
5/19/76

TABLE 9

SULFUR BALANCE

Cut	Cut, Wt. % of Crude	Total Sulfur, Wt. % in Cut	Total Sulfur, Wt. % in Crude
165 - 220	0.55	1.02	0.0056
220 - 280	0.10	1.13	0.0011
280 - 340	1.83	0.96	0.0176
340 - 380	1.96	0.83	0.0163
380 - 480	5.95	0.74	0.0440
480 - 520	4.34	0.82	0.0356
520 - 600	6.87	0.69	0.0474
600 - 650	5.53	0.74	0.0409
650 - 700	5.80	0.69	0.0400
700 - 750	5.70	0.61	0.0348
750 - 800	5.48	0.58	0.0318
800 - 850	6.03	0.54	0.0326
850 - 900	16.60	0.57	0.0946
900+	33.26	0.54	0.1796
TOTAL	100.00		0.6219
In Whole Crude			0.63

DTR #171
5/19/76

TABLE 10

NITROGEN BALANCE

Cut	Cut, Wt. % of Crude	Total Nitrogen, Wt% in Cut	Total Nitrogen, Wt% in Crude
165 - 220	0.55	0.05	0.0003
220 - 280	0.10	0.14	0.0001
280 - 340	1.83	0.74	0.0135
340 - 380	1.96	1.23	0.0241
380 - 480	5.95	0.96	0.0571
480 - 520	4.34	1.27	0.0551
520 - 600	6.87	1.72	0.1182
600 - 650	5.53	1.75	0.0968
650 - 700	5.80	2.02	0.1172
700 - 750	5.70	2.08	0.1186
750 - 800	5.48	2.01	0.1101
800 - 850	6.03	1.74	0.1049
850 - 900	16.60	1.84	0.3054
900+	33.26	2.42	0.8049
TOTAL			1.9263
In Whole Crude			1.90

TABLE 11

OXYGEN BALANCE

Cut	Cut, Wt. % of Crude	Total Oxygen, Wt. % in Cut	Total Oxygen, Wt. % in Crude
165 - 220	0.55	0.27	0.0015
220 - 280	0.10	0.28	0.0003
280 - 340	1.83	0.66	0.0121
340 - 380	1.96	1.15	0.0225
380 - 480	5.95	1.28	0.0762
480 - 520	4.34	1.47	0.0638
520 - 600	6.87	1.18	0.0811
600 - 650	5.53	1.32	0.0730
650 - 700	5.80	1.13	0.0655
700 - 750	5.70	1.13	0.0644
750 - 800	5.48	1.07	0.0586
800 - 850	6.03	0.91	0.0549
850 - 900	16.60	0.98	0.1627
900+	33.26	0.95	0.3160
TOTAL			1.0526
In Whole Crude			1.24

DTR #171
5/19/76 HEA

TABLE 12

CARBON-HYDROGEN BALANCE

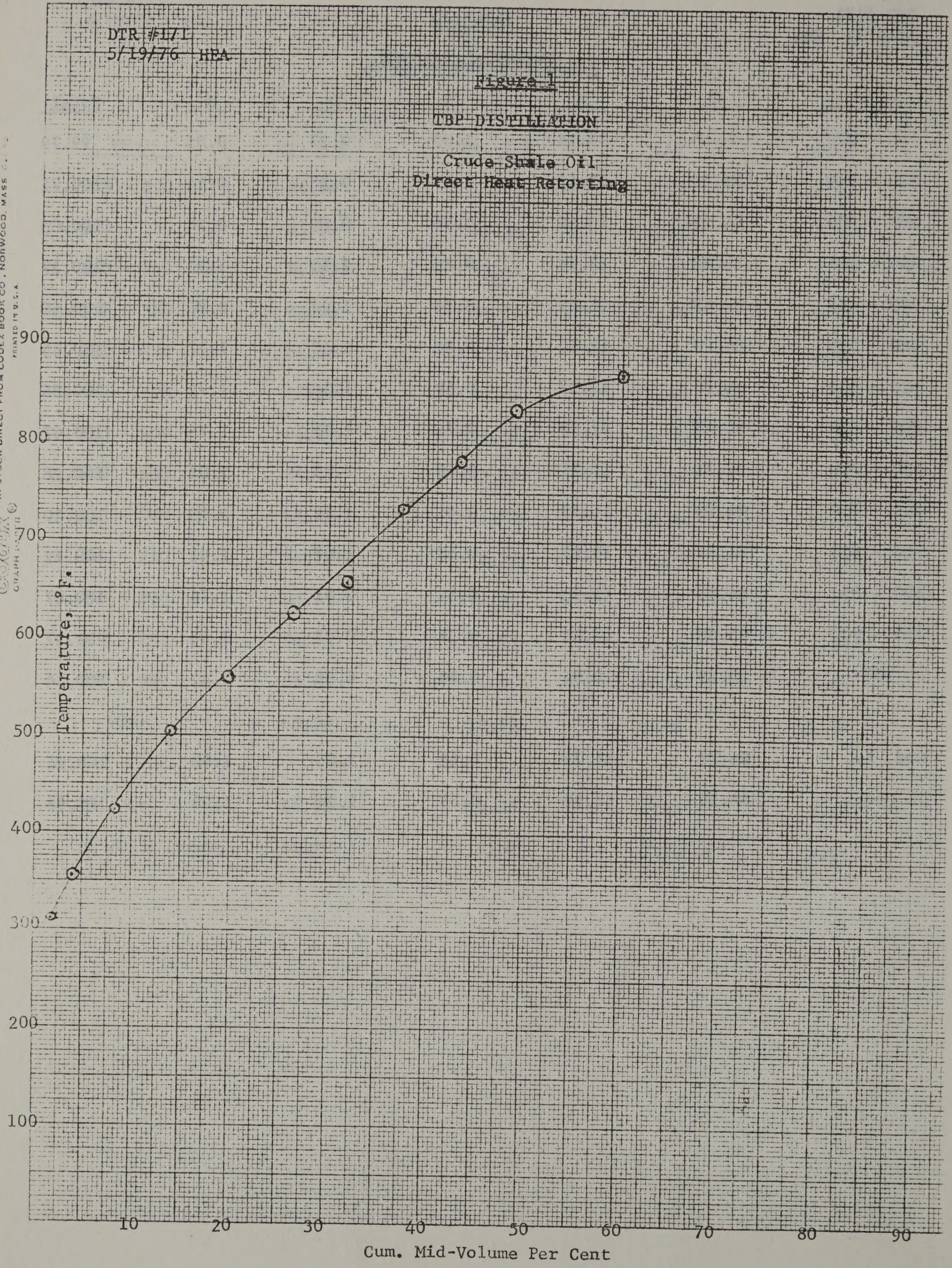
Cut	Wt. % C	Wt. % H	C/H	H/C Atomic Ratio
165 - 220	84.84	13.61	6.23	1.93
220 - 280	85.60	13.56	6.31	1.90
280 - 340	84.23	13.46	6.26	1.92
340 - 380	83.88	13.18	6.36	1.89
380 - 480	84.49	13.13	6.43	1.87
480 - 520	84.29	12.60	6.69	1.80
520 - 600	84.70	12.57	6.74	1.78
600 - 650	84.47	12.19	6.93	1.73
650 - 700	84.73	11.71	7.24	1.66
700 - 750	84.79	11.79	7.19	1.67
750 - 800	84.77	11.69	7.25	1.66
800 - 850	84.96	11.92	7.13	1.69
850 - 900	85.03	11.55	7.36	1.63
900+	85.29	10.94	7.80	1.54
Wtd. Av.	84.91	11.73	7.24	1.66
In Whole Crude	84.20	11.69	7.20	1.67

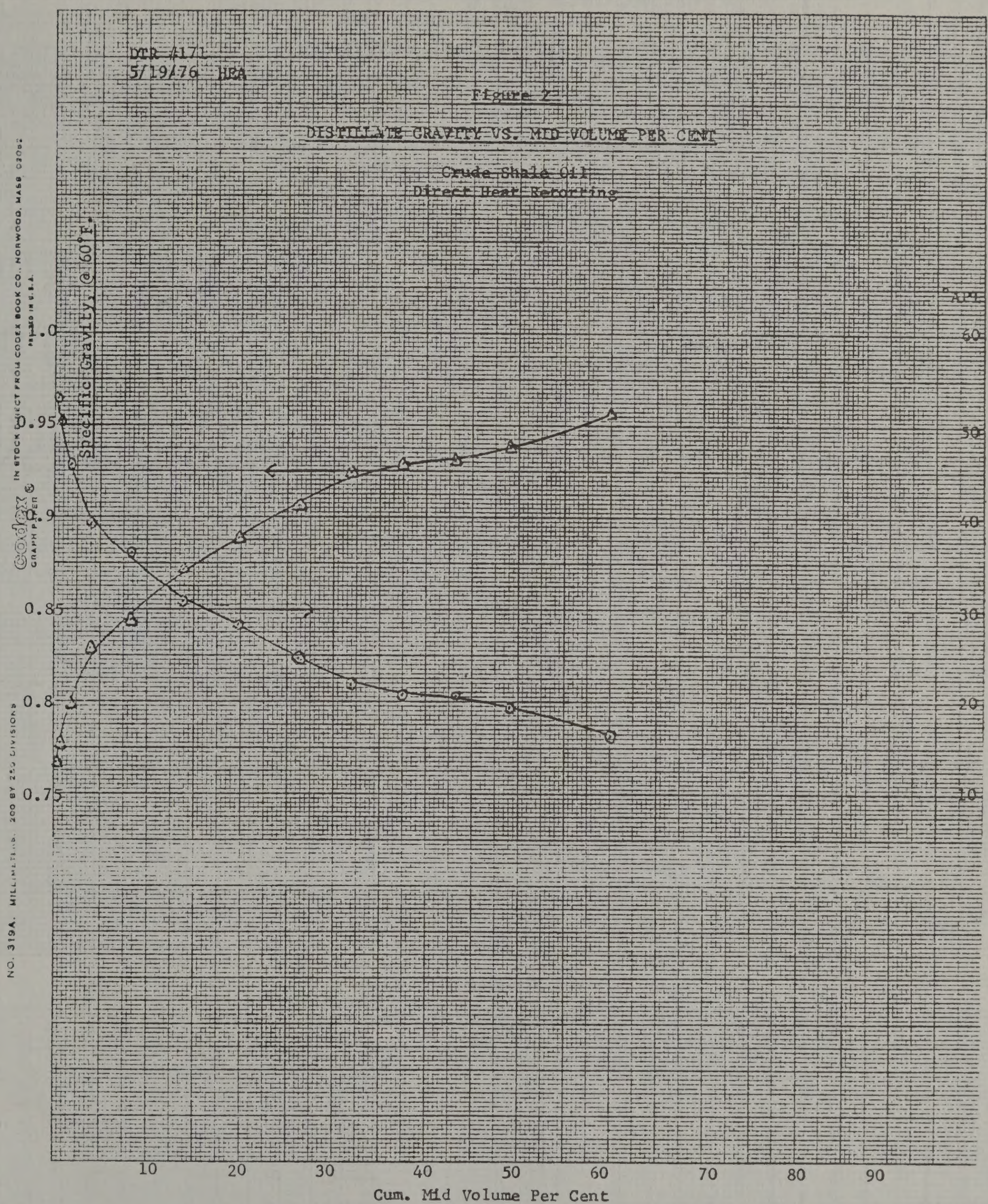
TABLE 13

ELEMENTAL BALANCE

Cut	C	H	S	O	N	Total
165 - 220	84.84	13.61	1.02	0.27	0.05	99.79
220 - 280	85.60	13.56	1.13	0.28	0.14	100.71
280 - 340	84.23	13.46	0.96	0.66	0.74	100.05
340 - 380	83.88	13.18	0.83	1.15	1.23	100.27
380 - 480	84.49	13.13	0.74	1.28	0.96	100.60
480 - 520	84.29	12.60	0.82	1.47	1.27	100.45
520 - 600	84.70	12.57	0.69	1.18	1.72	100.86
600 - 650	84.47	12.19	0.74	1.32	1.75	100.47
650 - 700	84.73	11.71	0.69	1.13	2.02	100.28
700 - 750	84.79	11.79	0.61	1.13	2.08	100.40
750 - 800	84.77	11.69	0.58	1.07	2.01	100.12
800 - 850	84.96	11.92	0.54	0.91	1.74	100.07
850 - 900	85.03	11.55	0.57	0.98	1.84	99.97
900+	85.29	10.94	0.54	0.95	2.42	100.14
Wtd. Av.	84.91	11.73	0.62	1.05	1.93	100.24
In Crude	84.20	11.69	0.63	1.24	1.90	99.66

DTR #171
5/19/76 HEA





DTR #171
5/19/76 HEA
Figure 2
DISTILLATE GRAVITY VS. MID VOLUME PER CENT
Crude Shale Oil
Direct Heat Retorting
Specific Gravity @ 60°F.
°API
1.0
0.95
0.9
0.85
0.8
0.75
60
50
40
30
20
10
10 20 30 40 50 60 70 80 90
Cum. Mid Volume Per Cent
NO. 319A. MILLIMETERS. 200 BY 250 DIVISIONS
codex GRAPH PAPER
IN STOCK DIRECT FROM CODEX BOOK CO., NORWOOD, MASS. 02062
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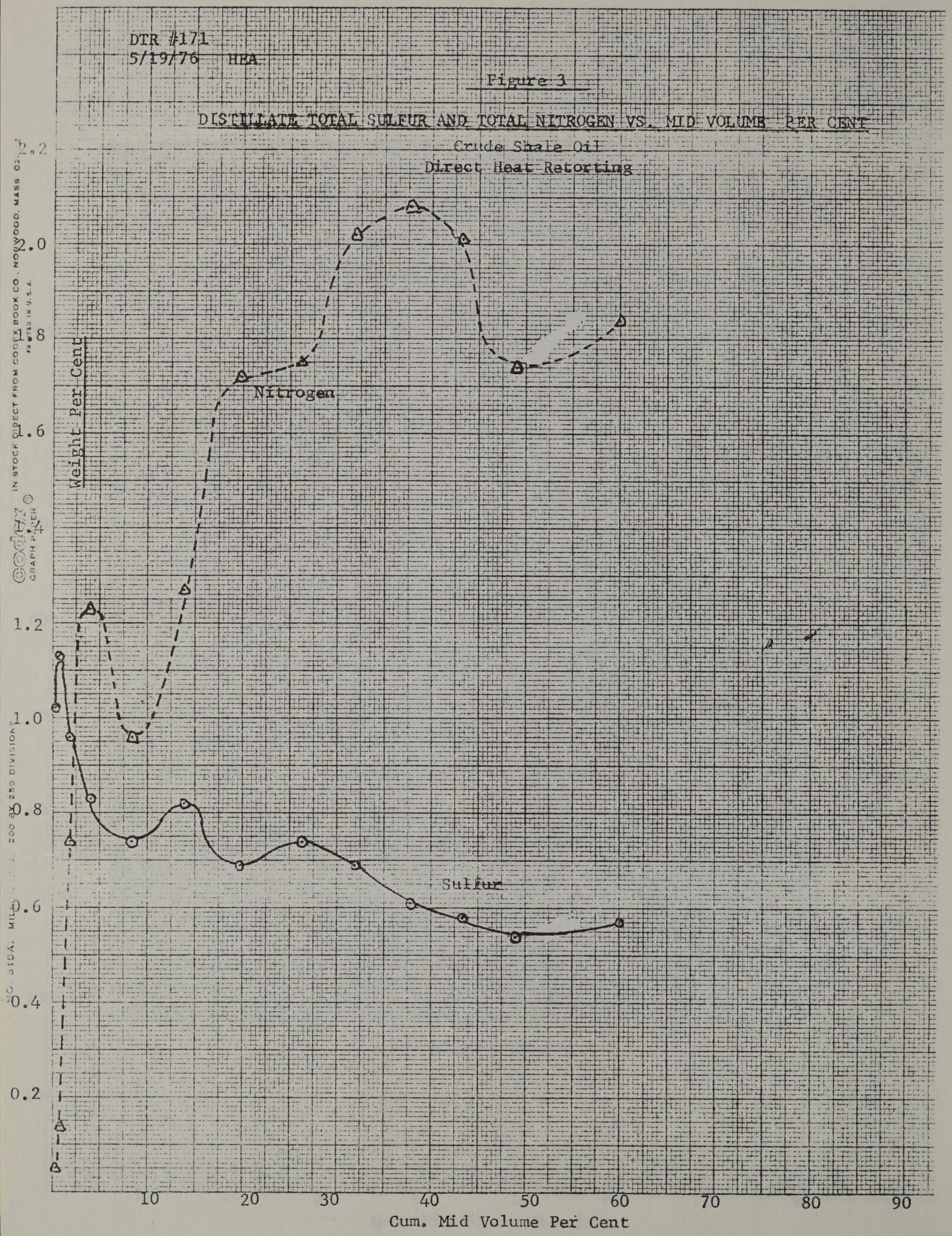
DTR #171
5/19/76 HEA
Figure 3
DISTILLATE TOTAL SULFUR AND TOTAL NITROGEN VS. MID VOLUME PER CENT
Crude Shale Oil
Direct Heat Retorting
Weight Per Cent
2.2
2.0
1.8
1.6
1.4
1.2
1.0
0.8
0.6
0.4
0.2
Nitrogen
Sulfur
10
20
30
40
50
60
70
80
90
Cum. Mid Volume Per Cent
CODEX GRAPH PAPER
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200 BY 250 DIVISIONS

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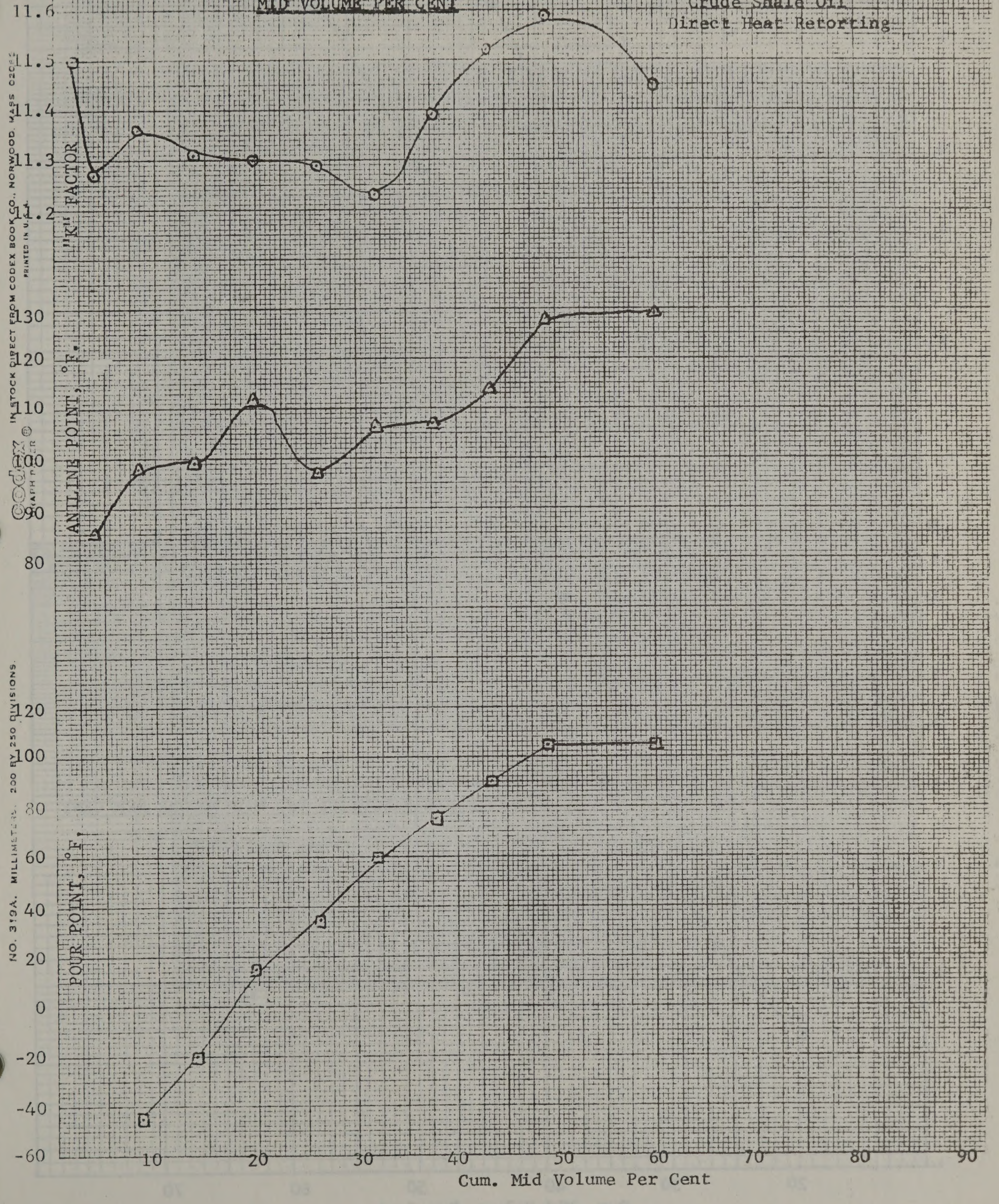
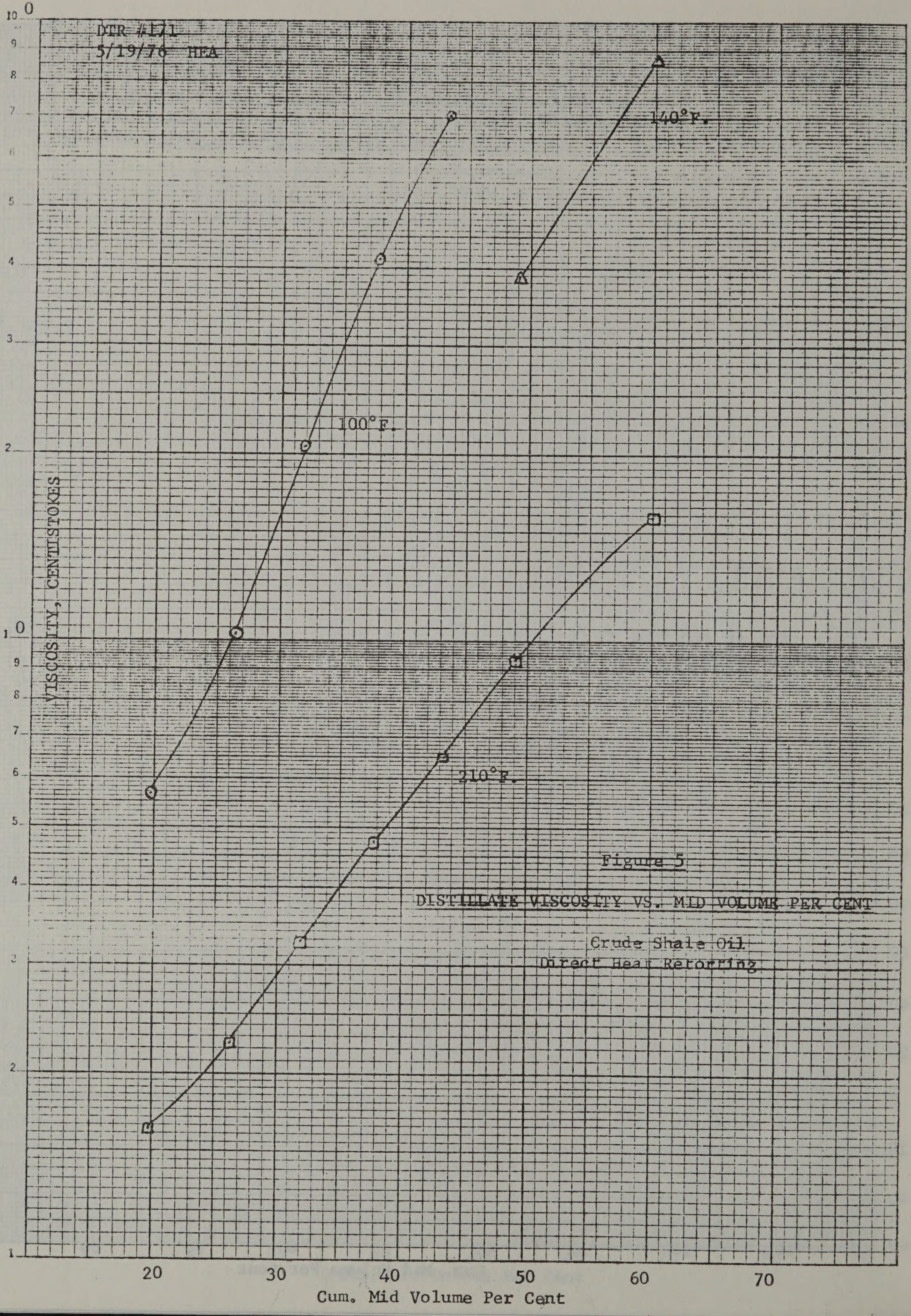
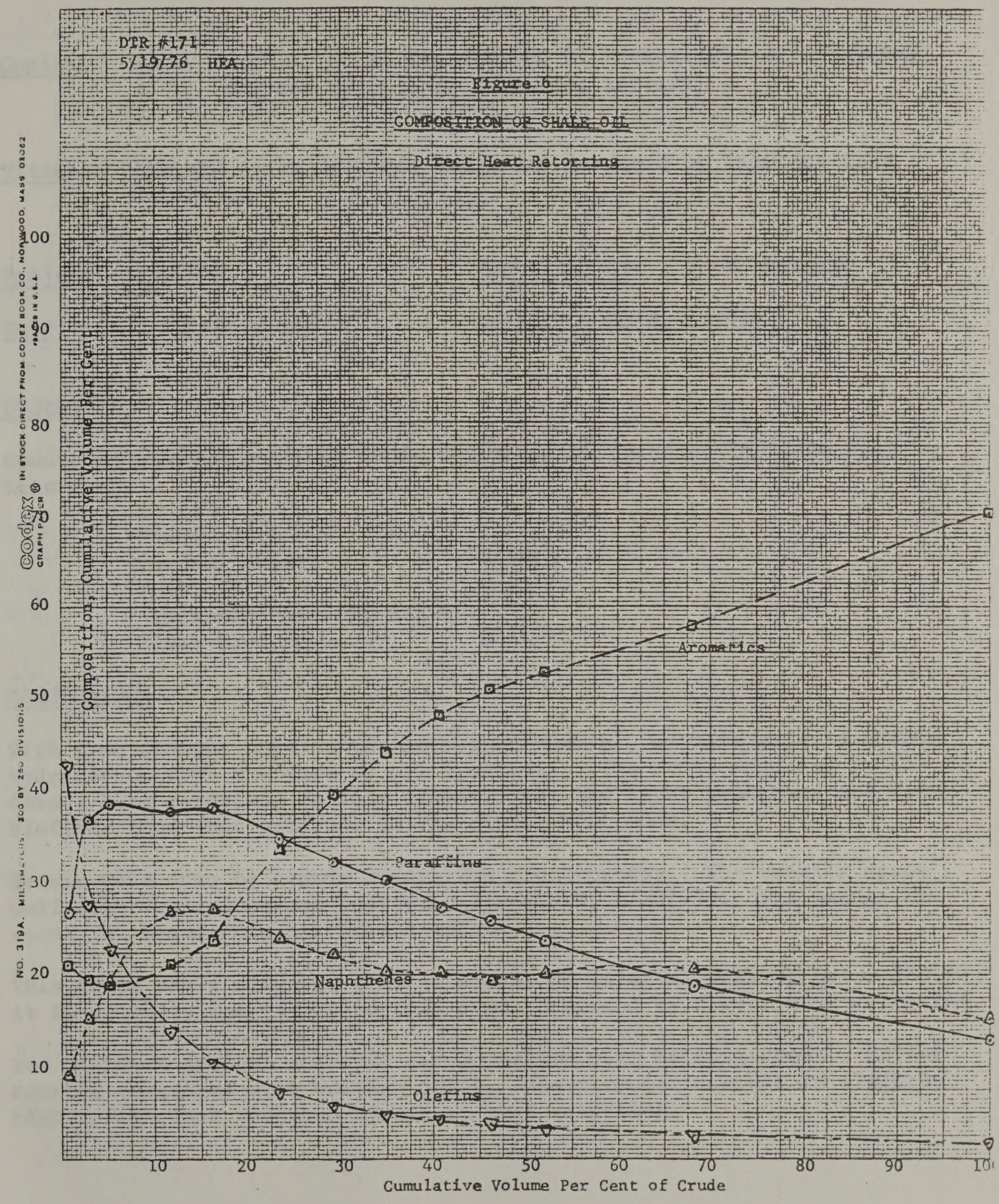
Figure 4

DISTILLATE "K" FACTOR, ANILINE POINT AND POUR POINT VS. MID VOLUME PER CENT

Crude Shale 011
Direct Heat Retorting




DTR #171
5/19/76 HEA
140°F.
100°F.
210°F.
VISCOSITY, CENTISTOKES
Cum. Mid Volume Per Cent
20
30
40
50
60
70
Figure 5
DISTILLATE VISCOSITY VS. MID VOLUME PER CENT
Crude Shale Oil
Direct Heat Retorting


DTR #171
5/19/76 HEA
Figure 6
COMPOSITION OF SHALE OIL
Direct Heat Retorting
Composition, Cumulative Volume Per Cent
Cumulative Volume Per Cent of Crude
Aromatics
Paraffins
Naphthenes
Olefins
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10
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60
70
80
90
100

SOHIO PETROLEUM COMPANY

DEVELOPMENT TECHNICAL RESPONSE NO. 172

Copies: S. K. Kunchal, E. K. Frazier, R. F. Paulus (2), J. C. Jansma, J. L. Petersen (3), J. E. Metcalfe, Library

Title: Limited Assay of Crude Shale Oil Produced by Indirect Heat Retorting

Project: 2330-03 Requested by: S. K. Kunchal

Date: 5/19/76 Author: H. E. Alford

OBJECTIVE

Conduct a limited assay of Crude Shale Oil produced by Indirect Heat Retorting.

Crude received:	2/17/76
Partial Assay:	4/1/76
Preliminary Assay: (missing PNA & O_2 data)	4/15/76
Final Limited Assay:	5/19/76

CONCLUSIONS

With some changes made on the mass spectrometer, we were able to obtain hydrocarbon type analyses on all fractions. The crude produced by indirect heat retorting is less aromatic and the light fractions are less olefinic than that produced in the direct heat mode.

Metals were done by atomic adsorption spectroscopy. The results agree well with those obtained last year (TR #4800, 5/28/75). The manner of retorting apparently has little effect.

This crude has a slightly greater amount of material boiling below 380°F.; it is slightly less volatile than crude produced by direct heat retorting.

The nitrogen content was high and increased with boiling point. Sulfur content decreased with boiling point. The nitrogen content is slightly higher than that produced by direct heat retorting.

The elemental analysis balances were good. Oxygen analyses were done by neutron activation.

All of the fractions were highly colored. The color appeared to deepen on standing.

Corrosive sulfur content of this crude was higher than that for the crude produced in the direct heat mode.

DISCUSSION

This assay was patterned after the one run a year ago (TR #4800, 5/28/75). It does not include all of the inspections normally obtained in a crude assay. This is by necessity in the case of the naphtha cuts, since only a small amount of light distillate was obtained. It does include an elemental analysis on each of the fractions.

This crude does give some gaseous products on distillation. Overall, there is less light distillate than in the crude shale oil produced in the direct heat mode.

With our revamped mass spectrometer, combined with FIA or elution analysis, we were able to obtain hydrocarbon-type analysis on all fractions. In addition to reporting the totals, we have also shown a breakdown of the hydrocarbons in each fraction. Naphthene content is reasonably constant over the entire boiling range; aromatics increase with boiling point. Olefins presented a unique problem in FIA separation; they did not fluoresce as they were supposed to. NMR analysis confirmed that the entire non-fluorescent band was olefinic. We believe the values to be correct. The cumulative totals are plotted.

Originally, oxygen determinations were made using our Perkin-Elmer Model 240 Elemental Analyzer. These values were reported in the Partial Assay of the crude. We then discovered we were getting interference, probably from sulfur compounds, using this technique. Consequently, oxygen determinations were repeated, using neutron activation. These values are reported in this assay.

H.E. Alford /vc.

HEA/vlm
5/24/76

HEA/vlm
2/11/76

SOHIO PETROLEUM COMPANY

CRUDE ASSAY

CRUDE Paraho Shale Oil - Indirect Heat Retorting

C.O.P. No. --- TS No. 76-05390-5 Work Requested by S. K. Kunchal
Sample Received 2/17/76 Sample Collected
Source of Sample Paraho Oil Shale Demonstration, Inc.

Table 1 - Properties of Settled Crude

Gravity, °API	19.1	Total Sulfur, Wt. %	0.62
Specific Gravity @ 60°F	0.9396	Total Nitrogen, Wt. %	2.05
Pour Point, °F	+85	RVP, lb.	---
Viscosity, SSU		Total Acid No., mg KOH/gm	2.411
@ 60°F	Too Heavy	Asphaltenes, Wt.% (STM-31)	1.051
@ 100°F	241	Ramsbottom Carbon, Wt. %	1.135
VGC	0.8989		

BS & W, Vol. %	0.05	(2.4, vol.% as received unsettled)	
Salt, lb./M Bbls.	0.774	(1.048, lb./M Bbls. as received unsettled	
Metals, ppm (AA)		Vis. @ 140°F. SSU 88.0	Carbon, Wt. % 84.88
As 22 Ni 2.9		Vis. @ 210°F. SSU 45.0	Hydrogen, Wt.% 11.57
Fe 55.0 V 0.33			Oxygen, Wt.% 1.28

Corrosive Sulfur

Temperature, °F.	Corrosive Sulfur, ppm		
	Hydrogen Sulfide-S	Mercaptan-S	Total
Ambient	---	---	---
Initial- 200	0.5	---	0.5
201 - 300	12.0	---	12.0
301 - 400	22.8	---	22.8
401 - 500	44.5	---	44.5
501 - 600	20.5	4.3	24.8
601 - 700	208	25	233
701 - 750	247	31	278
Purge	12.4	6.6	19.0
Total	567.7	66.9	634.6
Total, #/M bbls.	186	22	208

Table 2 - Hempel Distillation (D-285) of Crude

IBP	178	Inspections on Residue (500+)	
Vol. % Rec. at 95°F		Specific Gravity @ 60°F	0.944
125°F		Gravity, °API	18.4
165°F		Vis. SSU @ 140°F.	244
200°F	1.0	Vis. SSU @ 210°F	65.7
250°F	1.3	Car. Res., Ramsbottom, wt. %	2.921
300°F	1.6	Sulfur in Coke, Wt. %	
350°F	3.0		
400°F	5.0	Approximate Composition, Vol. %	
450°F	8.6	C_5 & Ltr. (evap. @ 125)	0
500°F	13.3	125°-400° Naphtha	6.4
Weight of 500+ Residue	243	400°-500° Kerosine	8.3
Volume of Residue	256	Gas Oil (Res.-Asph.)	69.1
Vol. % Residue	85.3	Asphalt (Calc.)	16.2
Vol. % Loss	1.4	Asphalt Quality "A"	0.90[illegible]

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Table 3

Crude Shale Oil-Indirect Heat Retorting C.O.P. Number ----

TBP Distillation of Crude

Cut	°API	Sp. Gr.	Wt. %	Vol. %	Cum. Vol. %
Gas		0.5577	0.33	0.56	0.56
55-165			0.00	0.00	0.56
165-220	41.1	0.8198	0.80	0.92	1.48
220-280			0	0	1.48
280-340	39.7	0.8265	0.47	0.54	2.02
340-380	37.9	0.8353	1.12	1.26	3.28
380-480	34.0	0.8550	4.91	5.40	8.68
480-520	30.3	0.8745	3.09	3.32	12.00
520-600	28.4	0.8849	7.65	8.12	20.12
600-650	24.6	0.9065	5.43	5.63	25.75
650-700	22.2	0.9206	6.56	6.70	32.45
700-750	20.5	0.9309	7.10	7.17	39.62
750-800	19.5	0.9371	7.62	7.64	47.26
800-850	17.9	0.9471	10.26	10.18	57.44
850-870	16.6	0.9554	4.26	4.19	61.63
870 + Btms	12.7	0.9813	39.53 40.40*	37.85 38.37*	100.00
Loss			0.87	0.52	
Total			100.00 100.00	100.00	

*corrected for loss

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2/11/76

DTR #172
5/19/76

CRUDE ASSAY - TABLE 4

HYDROCARBON TYPE ANALYSIS BY MS

Crude: Shale Oil - Indirect Heat Retorting

	Vol. %								
Cut Temperature, °F.	55-165*	165-220	220-280	280-340	340-380	380-480	480-520		
Paraffins	xxxx	12.8	xxxx	28.3	30.3	32.6	43.9		
Cycloparaffins									
1 Ring		6.7		12.2	14.1	8.6	5.3		
2 Ring		0.8		5.1	6.1	10.9	11.1		
3 Ring									
4 Ring									
5 Ring									
6 Ring									
Total Cycloparaffins		7.5		17.3	20.2	19.5	16.4		
Aromatics									
Alkyl Benzenes		58.5		26.3	18.7	12.1	6.4		
Naphthene Benzenes		1.0		1.3	5.2	15.0	9.5		
Dinaphthene Benzenes									
Naphthalenes				0.1	0.6	4.9	9.6		
Acenaphthenes, Biphenyls						1.0	2.9		
Acanaphthalenes, Fluorenes						2.5	4.4		
Phenanthrenes, Anthracenes									
Naphthene Phenanthrenes									
Pyrenes									
Chrysenes									
Perylenes									
Dibenzo Anthracenes									
Benzothiophenes						1.6	2.5		
Dibenzothiophenes									
Naphthobenzothiophenes									
Total Aromatics		59.5		27.7	24.5	37.1	35.3		
Olefins		20.2		26.7	25.0	10.8	4.4		

HEA/vlm
2/11/76

DTR #172
5/19/76 HEA

CRUDE ASSAY - TABLE 4

HYDROCARBON TYPE ANALYSIS BY MS

Crude: Shale Oil - Indirect Heat Retorting

	Wt. %								
Cut Temperature, °F.	520-600	600-650	650-700	700-750	750-800	800-850	850-870	870+	
Paraffins	31.4	22.3	22.1	15.5	11.7	23.2	2.0	Ins. Samp.	
Cycloparaffins									
1 Ring	10.1	9.1	10.5	9.3	7.1	8.8			
2 Ring	2.9	4.5	2.2	3.7	4.7	2.1			
3 Ring	1.1	3.0	0.5	2.6	2.0	2.2	18.4		
4 Ring	0.9	1.3	0.2	1.0	1.4	1.7	5.4		
5 Ring			0.1	0.4	0.5	0.3	2.2		
6 Ring	--	--	--	--	0.3	0.2	1.8		
Total Cycloparaffins	15.0	17.9	13.5	17.0	16.0	15.3	27.8		
Aromatics									
Alkyl Benzenes	19.8	16.4	19.1	24.6	18.9	15.8	22.1	41.2	
Naphthene Benzenes	8.8	8.7	9.8	10.1	10.2	6.9	9.1	10.3	
Dinaphthene Benzenes	10.0	9.9	8.8	9.2	12.2	8.6	9.8	10.2	
Naphthalenes	7.9	6.6	8.3	6.5	8.0	8.4	10.0	13.4	
Acenaphthenes, Biphenyls	2.6	6.4	6.5	5.1	6.4	5.8	6.6	5.0	
Acanaphthalenes, Fluorenes	1.2	4.1	5.1	5.1	5.9	6.2	6.7	6.1	
Phenanthrenes, Anthracenes	1.2	2.9	4.6	4.1	4.9	4.9	4.7	2.8	
Naphthene Phenanthrenes		0.4	0.5	0.8	1.5	1.5	0.4		
Pyrenes	0.1	0.8	0.3	0.8	1.7	1.8	0.8		
Chrysenes		0.4	0.3	0.1	0.3	0.5			
Perylenes									
Dibenzo Anthracenes									
Benzothiophenes		2.0	0.5	0.8	1.9	0.9			
Dibenzothiophenes	1.8	1.1	0.6	0.1	0.4	0.2			
Naphthobenzothiophenes	0.2	0.1		0.2					
Total Aromatics	53.6	59.8	64.4	67.5	72.3	61.5	70.2	89.0	

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2/11/76

TABLE 5
PROPERTIES OF NAPHTHAS

	165-220	280-340	340-380
Cum. Mid Volume %	1.02	1.75	2.65
Vol. % of Crude	0.92	0.54	1.26
Cum. Vol. % of Crude	1.48	2.02	3.28
Gravity, °API	41.1	39.7	37.9
Specific Gravity @ 60°F.	0.8198	0.8265	0.8353
ASTM Dist., D-86, °F.			
IBP	150	Ins. Samp.	342
@ 10% Evap.	206		348
@ 30% Evap.	226		355
@ 50% Evap.	240		360
@ 70% Evap.	252		370
@ 90% Evap.	273		382
EP	293		396
% Rec.	98		99
% Res.	1		1
Total Sulfur, Wt.%	1.43	1.51	1.04
Mercaptan Sulfur, ppm	xxxx	xxxx	Nil
Total Nitrogen, Wt.%	0.18	1.10	1.45
UOP "K" Factor	10.83	xxxx	11.21
Aniline Point, °F.	xxxx	xxxx	78.5
Cetane Index	xxxx	xxxx	27.0
Smoke Point, mm	xxxx	xxxx	14.0
PNA by MS, Vol.%			
Paraffins	12.8	28.2	30.3
Naphthenes	7.5	17.3	20.2
Aromatics	59.5	27.7	24.5
Olefins	20.2	26.7	25.0

DTR #172
5/19/76 HEA

DTR #172
5/19/76 HEA

TABLE 6

PROPERTIES OF MIDDLE DISTILLATES

	380-480	480-520	520-600	600-650
Cum. Mid. Vol. %	5.98	10.34	16.06	22.94
Vol. % of Crude	5.40	3.32	8.12	5.63
Cum. Vol. % of Crude	8.68	12.00	20.12	25.75
Gravity, °API	34.0	30.3	28.4	24.6
Specific Gravity @ 60°F.	0.8550	0.8745	0.8849	0.9065
ASTM Dist., D-86, °F.				
IBP	395	180	502	555
@ 10% Evap.	410	465	530	587
@ 30% Evap.	424	488	538	594
@ 50% Evap.	434	495	543	600
@ 70% Evap.	445	500	550	606
@ 90% Evap.	460	505	562	616
EP	475	514	584	630
% Rec.	99	99	98.5	98
% Res.	1	1	1.5	2
Vanadium, ppm	xxxx	xxxx	0.01	0.01
Nickel, ppm	xxxx	xxxx	0.08	0.08
Iron, ppm	xxxx	xxxx	1.7	0.9
Vis., CS/100°F.	xxxx	xxxx	5.63	10.77
Vis. SSU/100°F.	xxxx	xxxx	44.4	61.5
Vis. CS/210°F.	xxxx	xxxx	1.62	2.31
Vis. SSU/210°F.	xxxx	xxxx	31.5	33.9
Total Sulfur, Wt. %	0.70	0.82	0.67	0.66
Mercap. Sulfur, ppm	102	67.8	88.8	59.5
Total Nitrogen, Wt. %	1.31	1.34	1.57	1.75
UOP "K" Factor	11.27	11.26	11.31	11.25
Paraffins, Vol. %	32.6	43.9	31.4*	22.3*
Naphthenes, Vol.%	19.5	16.4	15.0*	17.9*
Aromatics, Vol. %	37.1	35.3	53.6*	59.8*
Olefins, Vol. %	10.8	4.4	-----	-----
Aniline Point, °F.	86	95	111	103
Pour Point, °F.	fl. @-40	-15	10	40
Freezing Point, °F.	too dark	too dark	xxxx	xxxx
Thermo. Vis. @ 60°F.	too dark	too dark	xxxx	xxxx
Ring Number	too dark	too dark	xxxx	xxxx
Cetane Index	34.4	37.1	40.4	40.4
Smoke Point, mm	15	14	xxxx	xxxx
Diesel Index	29.2	28.8	31.5	25.3
T. Acid No., mg KOH/g.	xxxx	xxxx	3.147	1.388
R. I. @ 140°F.	xxxx	xxxx	too dark	too dark

*Wt. %

DTR #172
5/19/76

TABLE 7

PROPERTIES OF THE HEAVY DISTILLATES

	650-700	700-750	750-800	800-850	850-870
Cum. Mid. Vol. %	29.10	36.04	43.44	52.35	59.54
Vol. % of Crude	6.70	7.17	7.64	10.18	4.19
Cum. Vol. % of Crude	32.45	39.62	47.26	57.44	61.63
Gravity, °API	22.2	20.5	19.5	17.9	16.6
Specific Gravity @ 60°F.	0.9206	0.9309	0.9371	0.9471	0.9554
ASTM Dist., D-1160, °F.					
IBP	600**	691	673	696	650
@ 10% Evap.	633	715	760	800	845
@ 30% Evap.	640	721	771	806	853
@ 50% Evap.	647	723	774	810	859
@ 70% Evap.	653	733	779	814	860
@ 90% Evap.	667	743	790	823	865
EP	678	754	806	835	876
% Rec.	98.5	98	98	98	98
% Res.	1.5	2	2	2	2
Vanadium, ppm	<0.01	0.01	0.01	0.02	0.03
Nickel, ppm	0.08	0.09	0.30	0.44	0.36
Iron, ppm	0.90	2.7	3.1	6.7	19.4
Vis. CS/100°F.	19.75	40.80	25.88*	46.50*	80.98*
Vis. SSU/100°F.	96.8	190.4	xxxx	xxxx	xxxx
Vis. CS/210°F.	3.29	4.77	6.85	10.23	14.54
Vis. SSU/210°F.	37.1	41.9	48.6	60	76.1
Total Sulfur, Wt. %	0.66	0.63	0.59	0.53	0.53
Mercap. Sulfur, ppm	65.6	81.2	70.7	66.0	57.6
Total Nitrogen, Wt. %	1.98	2.08	2.04	1.81	1.90
UOP "K" FACTOR	11.24	11.36	11.45	11.43	11.48
Paraffins, Wt.%	22.1	15.5	11.7	23.2	2.0
Naphthenes, Wt.%	13.5	17.0	16.0	15.3	27.8
Aromatics, Wt.%	64.4	67.5	72.3	61.5	70.2
Aniline Point, °F.	101	100	110	125	116
Pour Point, °F.	55	75	90	95	105
Cetane Index,	41.4	46.5	49.7	50.0	52.0
T. Acid No, mg KOH/g.	0.858	0.457	0.374	0.196	0.059
R. I. @ 140°F.	too dark	too dark	too dark	too dark	too dark

*Vis. @ 140°F.
**D-86 Dist.

DTR #172
5/19/76 HEA

TABLE 8

PROPERTIES OF THE RESIDUE

	870+
Vol. % of Crude	38.37
Cum. Vol. % of Crude	100.00
Gravity, °API	12.7
Specific Gravity @ 60°F.	0.9813
Abs. Vis. @ 140°F., poises	14.7
Kin. Vis. @ 140°F., CS	1525
Kin. Vis. @ 210°F., CS	114.3
Vis. @ 210°F., SSU	532
Kin. Vis. @ 275°F., CS	26.9
Furol Vis. @ 275°F., SSF	12.8
Total Sulfur, Wt. %	0.52
Total Nitrogen, Wt.%	2.49
Vanadium, ppm	0.84
Nickel, ppm.	8.8
Iron, ppm	203
Insolubles in Pentane, Wt.%	7.85
Paraffins, Wt.%	11.0
Naphthenes, Wt.%	
Aromatics, Wt.%	89.0

TABLE 9

SULFUR BALANCE

Cut	Cut, Wt.% of Crude	Total Sulfur, Wt. % in Cut	Total Sulfur, Wt. % in Crude
165 - 220	0.80	1.43	0.0114
280 - 340	0.47	1.51	0.0071
340 - 380	1.12	1.04	0.0116
380 - 480	4.91	0.70	0.0344
480 - 520	3.09	0.82	0.0253
520 - 600	7.65	0.67	0.0513
600 - 650	5.43	0.66	0.0358
650 - 700	6.56	0.66	0.0433
700 - 750	7.10	0.63	0.0447
750 - 800	7.62	0.59	0.0450
800 - 850	10.26	0.53	0.0544
850 - 870	4.26	0.53	0.0226
870+	40.40	0.52	0.2101
Total	99.67		0.5970
in Whole Crude			0.62

TABLE 10

NITROGEN BALANCE

Cut	Cut, Wt.% of Crude	Total Nitrogen, Wt. % in Cut	Total Nitrogen, Wt. % in Crude
165 - 220	0.80	0.18	0.0014
280 - 340	0.47	1.10	0.0052
340 - 380	1.12	1.45	0.0162
380 - 480	4.91	1.31	0.0643
480 - 520	3.09	1.34	0.0414
520 - 600	7.65	1.57	0.1201
600 - 650	5.43	1.75	0.0950
650 - 700	6.56	1.98	0.1299
700 - 750	7.10	2.08	0.1477
750 - 800	7.62	2.04	0.1554
800 - 850	10.26	1.81	0.1857
850 - 870	4.26	1.90	0.0809
870+	40.40	2.49	1.0060
Total	99.67		2.0492
in Whole Crude			2.05

DTR #172
5/19/76 HEA

TABLE 11

OXYGEN BALANCE

Cut	Cut, Wt.% of Crude	Oxygen, Wt.% in Cut	Oxygen, Wt.% in Crude
165 - 220	0.80	0.36	0.0029
280 - 340	0.47	0.55	0.0026
340 - 380	1.12	0.86	0.0096
380 - 480	4.91	1.36	0.0668
480 - 520	3.09	1.17	0.0362
520 - 600	7.65	1.22	0.0933
600 - 650	5.43	1.14	0.0619
650 - 700	6.56	1.16	0.0761
700 - 750	7.10	1.13	0.0802
750 - 800	7.62	1.09	0.0831
800 - 850	10.26	0.92	0.0944
850 - 870	4.26	1.00	0.0426
870+	40.40	0.97	0.3919
	99.67		1.0416
Total in Whole Crude			1.28

TABLE 12

CARBON-HYDROGEN BALANCE

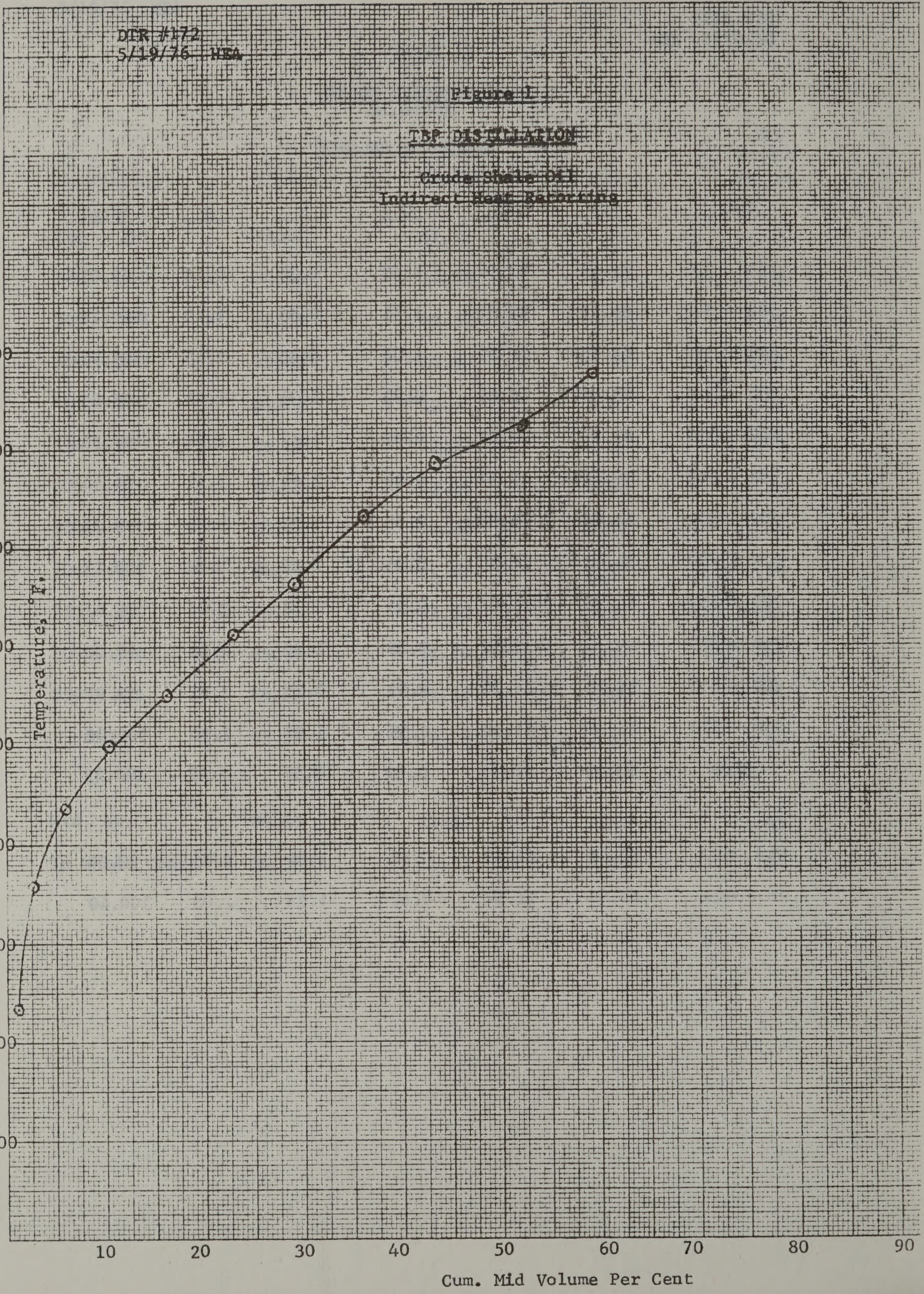
Cut	Wt.% C	Wt.% H	C/H	H/C Atomic Ratio
165 - 220	85.97	11.07	7.77	1.55
280 - 340	84.26	12.36	6.82	1.76
340 - 380	83.85	12.52	6.70	1.79
380 - 480	83.86	12.62	6.65	1.81
480 - 520	83.81	12.42	6.75	1.78
520 - 600	84.11	12.37	6.80	1.77
600 - 650	84.08	12.08	6.96	1.73
650 - 700	84.47	11.86	7.12	1.69
700 - 750	84.21	11.62	7.25	1.66
750 - 800	83.76	11.52	7.27	1.65
800 - 850	85.01	11.70	7.27	1.65
850 - 870	85.07	11.58	7.35	1.63
870+	85.39	10.95	7.80	1.54
Wtd. Av.	84.48	11.49	7.35	1.63
In Whole Crude	84.88	11.57	7.34	1.64

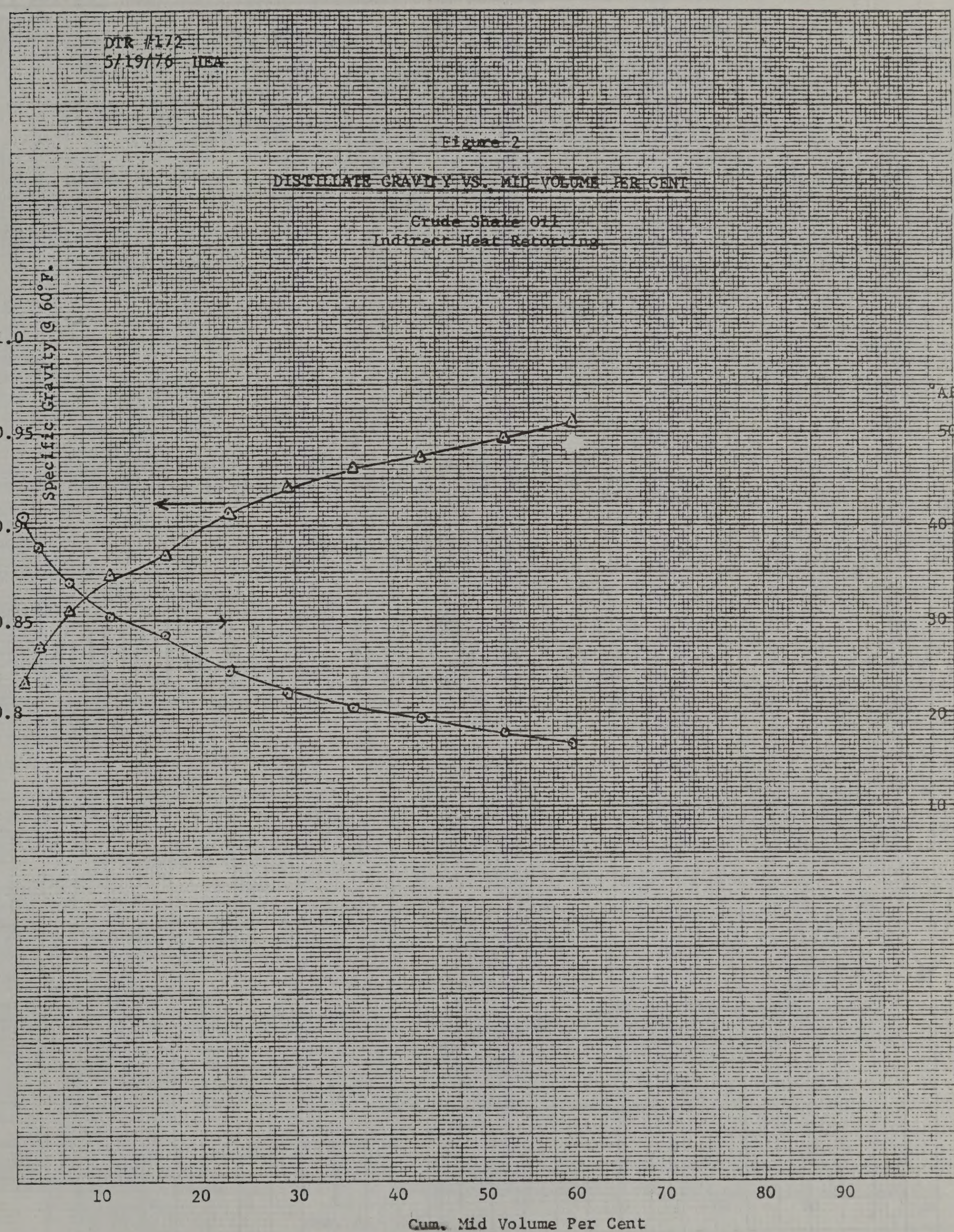
DTR #172
5/19/76 HEA

TABLE 13

ELEMENTAL BALANCE

Cut	C	H	O	S	N	Total
165 - 220	85.97	11.07	1.43	0.36	0.18	99.01
380 - 340	84.26	12.36	1.51	0.55	1.10	99.78
340 - 380	83.85	12.52	1.04	0.86	1.45	99.72
380 - 480	83.86	12.62	0.70	1.36	1.31	99.85
480 - 520	83.81	12.42	0.82	1.17	1.34	99.56
520 - 600	84.11	12.37	0.67	1.22	1.57	99.94
600 - 650	84.08	12.08	0.66	1.14	1.75	99.71
650 - 700	84.47	11.86	0.66	1.16	1.98	100.13
700 - 750	84.21	11.62	0.63	1.13	2.08	99.67
750 - 800	83.76	11.52	0.59	1.09	2.04	99.00
800 - 850	85.01	11.70	0.53	0.92	1.81	99.97
850 - 870	85.07	11.58	0.53	1.00	1.90	100.08
870+	85.39	10.95	0.52	0.97	2.49	100.32
Wtd. Av.	84.48	11.49	0.60	1.04	2.05	99.66
In Crude	84.88	11.57	0.62	1.28	2.05	100.40


DTR #172
5/19/76 HEA
Figure 1
TBP DISTILLATION
Crude Shale Oil
Indirect Heat Retorting
Temperature, °F.
900
800
700
600
500
400
300
200
100
10
20
30
40
50
60
70
80
90
Cum. Mid Volume Per Cent

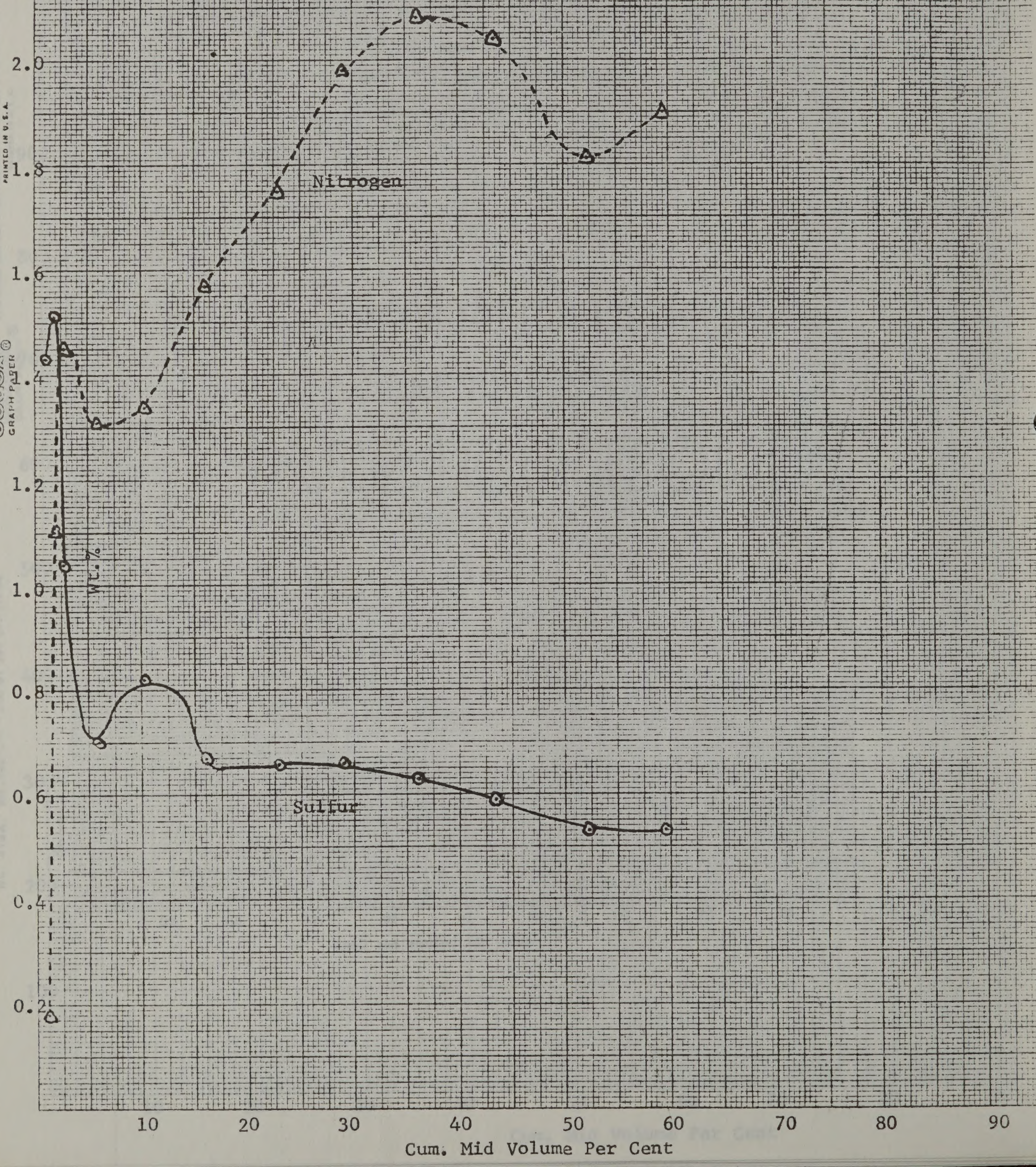

DTR #172
5/19/76 HEA
Figure 2
DISTILLATE GRAVITY VS. MID VOLUME PER CENT
Crude Shale Oil
Indirect Heat Retorting
Specific Gravity @ 60°F.
1.0
0.95
0.9
0.85
0.8
°API
50
40
30
20
10
10
20
30
40
50
60
70
80
90
Cum. Mid Volume Per Cent

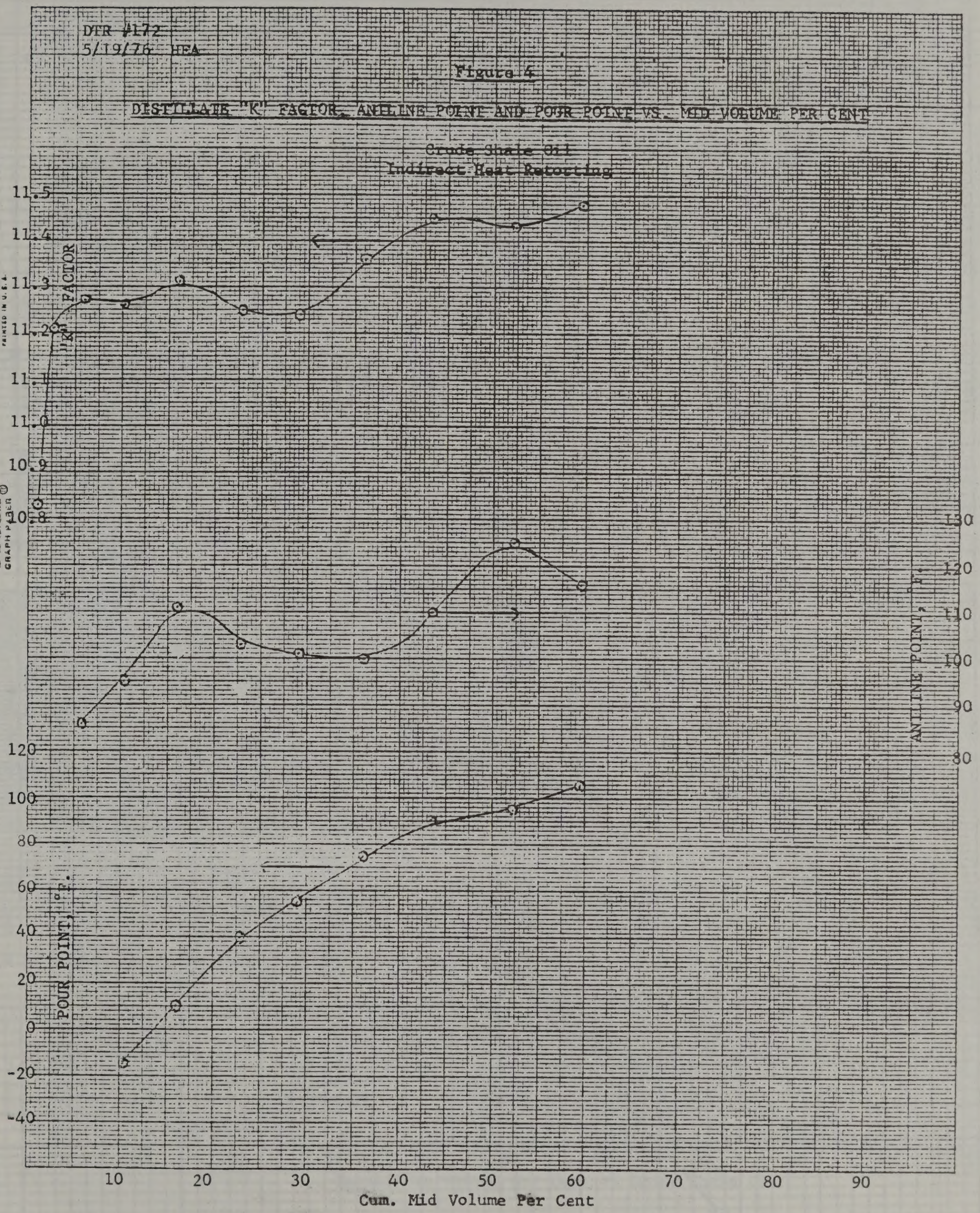
DTR #172
5/19/76 HEA

Figure 3

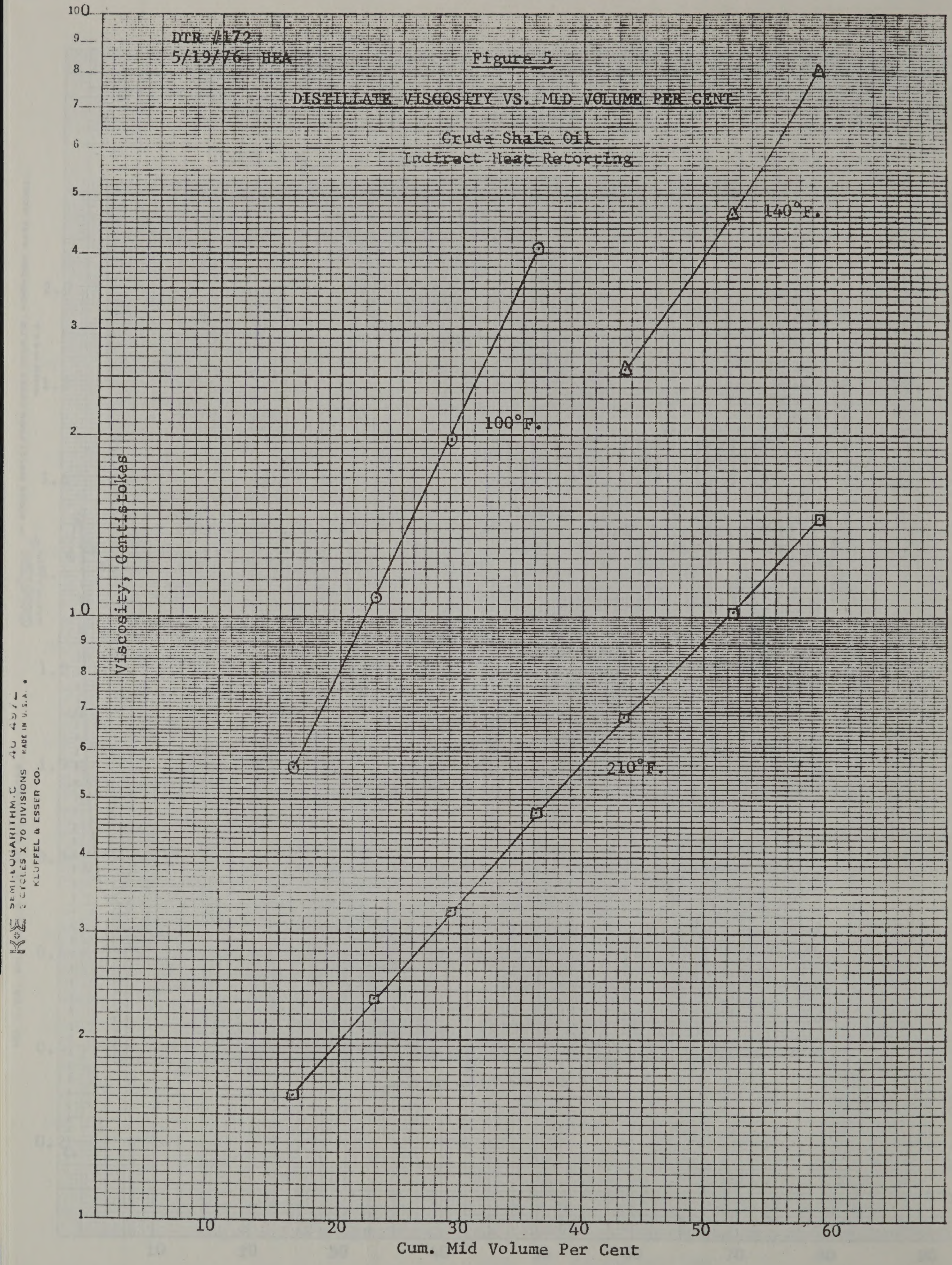
DISTILLATE TOTAL SULFUR AND TOTAL NITROGEN VS. MID VOLUME PER CENT

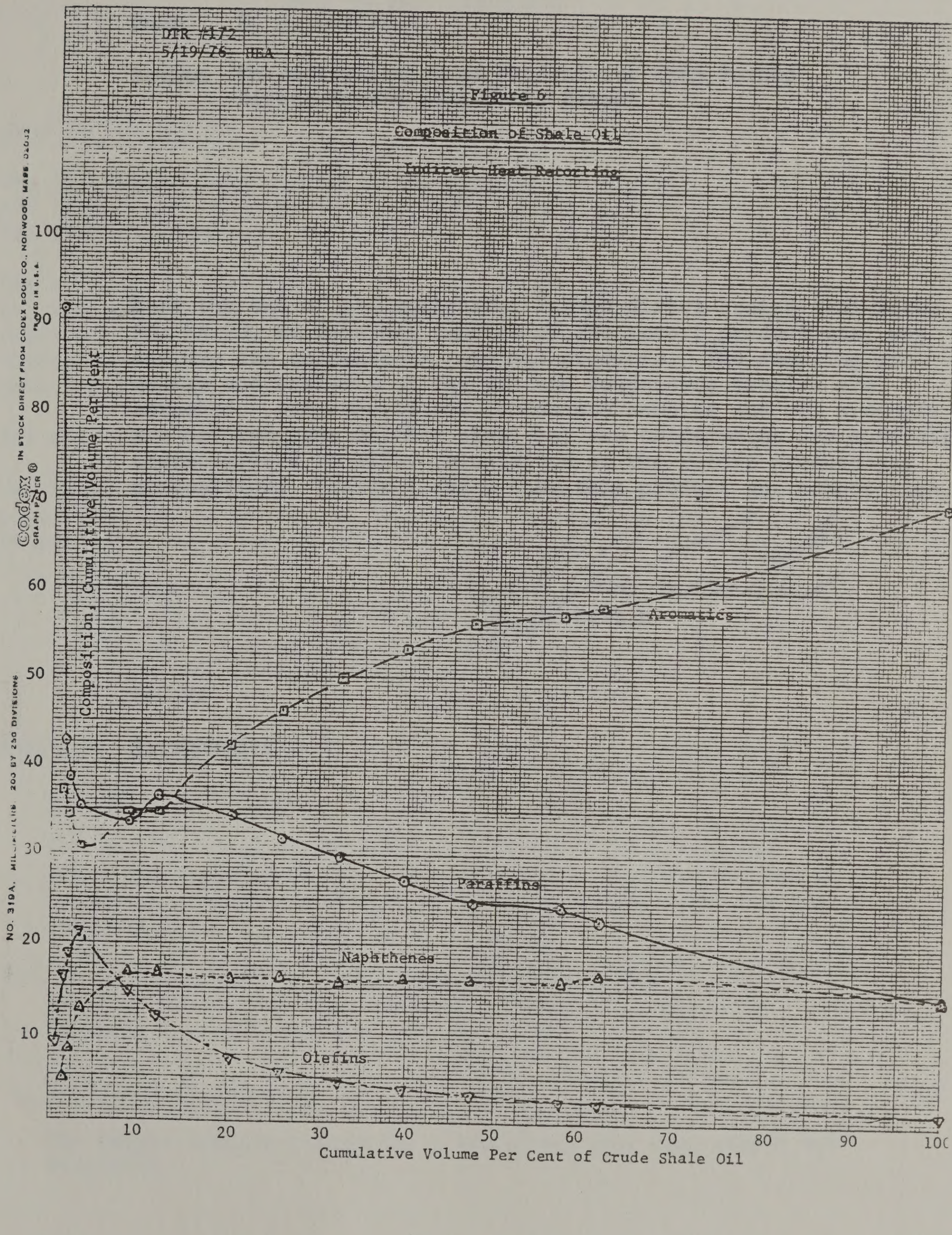
Crude Shale Oil
Indirect Heat Retorting





DTR #172
5/19/76 HFA
Figure 4
DISTILLATE "K" FACTOR, ANILINE POINT AND POUR POINT VS. MID VOLUME PER CENT
Crude Shale Oil
Indirect Heat Retorting
"K" FACTOR
POUR POINT, °F.
ANILINE POINT, °F.
Cum. Mid Volume Per Cent


DTR #172
5/19/76 HEA
Figure 5
DISTILLATE VISCOSITY VS. MID VOLUME PER CENT
Crude Shale Oil
Indirect Heat Retorting
140°F.
100°F.
210°F.
Viscosity, Centistokes
Cum. Mid Volume Per Cent
10
20
30
40
50
60
SEMI-LOGARITHMIC 2 CYCLES X 70 DIVISIONS
KEUFFEL & ESSER CO. MADE IN U.S.A.


DTR #172
5/19/76 HEA
Figure 6
Composition of Shale Oil
Indirect Heat Retorting
Composition, Cumulative Volume Per Cent
Cumulative Volume Per Cent of Crude Shale Oil
Aromatics
Paraffins
Naphthenes
Olefins
10
20
30
40
50
60
70
80
90
100
codex GRAPH PAPER
IN STOCK DIRECT FROM CODEX BOOK CO., NORWOOD, MASS.
NO. 319A.

AtlanticRichfieldCompany Internal Correspondence

Date: January 20, 1976

To: Mr. R. E. Styring, Jr.

From: D. J. Curtin

Subject: Characterization of Product Gas from Paraho Direct-Heated Semi-Works Retort

Near the end of the successful Paraho direct-heated semi-works Run SW-20, we obtained samples of the retort product gas, wet and dry ice condensates, and oil products. The sampling procedure and analyses of the gas and condensate samples are attached. Analyses of the condensate samples and oil products are not complete at this time, but the condensates are sufficiently characterized to allow calculation of the retort product gas composition. Tables 1 and 2 show this product gas composition.

D. J. Curtin

DJC:vs

Attachments

PARAHO RETORT GAS ANALYSIS

(Run SW-20 - 11/25/75)

SAMPLING PROCEDURE

The following procedure was used to obtain wet and dry ice trap gas and liquid samples from the semi-works retort recycle gas line during Run SW-20, on November 25, 1975.

Gas from the sample tap located on the blower discharge flowed through wet ice and dry ice traps connected in series. The traps consisted of coils of 5/8" O.D. aluminum tubing, 12 ft. and 10 ft. long, respectively, connected to 6000 c.c. stainless steel sampling containers. The two baths were filled with water-ice, and acetone-dry ice mixtures.

Gas from the dry ice trap was metered in a wet test meter and vented.

Two runs were attempted. Both runs were prematurely terminated because of plugging in the dry ice trap. The dry ice trap gas volume in each case was about 70 SCF. Samples of these streams were obtained:

Gas from dry ice trap,
Gas and liquid in dry ice trap,
Liquid from wet ice trap, and
Control room gas samples.

LABORATORY PROCEDURE

Wet Ice Trap Naphtha

The sample container was chilled to 32°F. The weights of water and hydrocarbons were measured by withdrawing the sample container contents into chilled receivers, separating the phases, and weighing.

The GC-TBP curve, an approximate component analysis, and the specific gravity of the sample obtained during Run 1 are attached. The sample from Run 2 was lost.

Dry Ice Trap Samples

The sample container from Run 1 had leaked and this sample was discarded.

Dry Ice Trap Samples (continued)

The sample from Run 2 was pressurized with helium to increase the pressure from ~2 psig to about 200 psig to facilitate sample handling. Liquid was withdrawn from the field sampling container (at 24°C) into small sample containers and weighed. The weight balance on the field sample container is attached.

The following analyses were performed:

GC Gas Analyses:

Vapor phase - container #2408
Dry Ice Trap Gas - container #2410

GC Liquid Analyses:

Liquid phase - container #2408
Simulated TBP
Component Analysis

Liquid Density (from container #2408) was measured.

CALCULATION PROCEDURE

Recombination of Dry Ice Trap Samples

The composition and quantity of liquid in the sample container at -108°F and 12 psia was determined by an equilibrium flash calculation at these conditions, using the vapor and liquid contents determined at 24°C. The -108°F liquid was recombined with the dry gas to obtain the vapor composition from the wet ice trap.

Two cases were calculated using:

(1) The actual weight of liquid removed from the sample container (40.219 gm. liquid).

(2) The liquid weight calculated from known vapor and liquid densities, container volume, and total sample weight. (50.401 gm. liquid)

All of the components in the naphtha samples were not identified. Molecular weights are needed for the conversion of weight to mole percent. The heavy fraction molecular weights were estimated from the API Data Book correlation (2B2.1). Molecular weights for the lower boiling point unidentified components were estimated from the component's boiling point (which, in turn, was estimated from the retention time in the gas chromatograph). Equilibrium constants for the flash calculation were obtained from the API Data Book.

Recombination of Wet Ice Trap Samples

The same procedure was used to convert from weight to mole percent. The wet ice trap condensate was recombined with the two dry ice trap cases.

Results

Molal balances and gas compositions for the two cases calculated are shown in the attached tables.

Table 1

AtlanticRichfieldCompany **Well Calculation Sheet—Short**

Title or object of calculations: Calculated Gas Compositions

Nº 86409

Problem | Field | Well | Date

From to Calculated by:

References: (BASED ON LIQUID WITHDRAWN FROM FIELD CONTAINER)

started 1/16/76

finished

Equation:

Concurrent sheets

Remarks:

Column no.	1	2	3–4	6	7	9	10–11	12
Name / Symbol / Source / Units	Dry Gas #2410 Mol%	gMols	Dry Ice Trap Liquid - Calc. Composition gMols	Gas Composition From Wet Ice Trap gMols	Mol%	WET ICE TRAP LIQUID, gmoles	TOTAL GAS SAMPLE, gmoles	TOTAL GAS SAMPLE, Mol%
H_2	4.42	3.851	.0001	3.85101	4.39	—	3.85101	4.377
O_2+Ar	0.93	.810	.00002	.81002	.92	—	.81002	.921
N_2	65.07	56.704	.00153	56.7055	64.62	—	56.70550	64.456
C_1	2.33	2.030	.00021	2.0302	2.31	—	2.03020	2.308
CO	2.01	1.752	.00022	1.75222	2.00	—	1.75222	1.992
CO_2	22.05	19.215	.01877	19.2337	21.92	—	19.23370	21.862
$C_2^=$	0.93	.810	.00163	.81163	.92	—	.81163	.923
C_2	0.95	.828	.00364	.83164	.95	.00002	.83166	.945
$C_3^=$	0.45	.392	.00762	.39962	.46	—	.39962	.454
C_3	0.47	.410	.00978	.41978	.48	.00014	.41992	.477
iC_4	0.06	.052	.00227	.05427	.06	.0001	.05428	.062
Butene-1	0.16	.139	.02138	.16038	.18	—	.16038	.182
nC_4	0.09	.078	.02559	.10359	.12	.00035	.10394	.118
Butene-2	0.02	.017	.00421	.02121	.02	—	.02121	.024
cis Butene-2	0.01	.009	.00596	.01496	.02	.00009	.01505	.017
$3MeC_4^=$	Trace	—	.00331	.00331	.004	.00004	.00335	.004
iC_5	0.01	.009	.01158	.02058	.02	.00011	.02069	.024
Pentene-1	0.02	.017	.01081	.02781	.03	—	.02781	.032
NC_5	0.02	.017	.05732	.07432	.08	.00071	.07503	.085
Trans Pentene-2			.00479	.00479	.005	.00016	.00495	.006
Cis Pentene-2			.00123	.00123	.001	.00031	.00154	.002
$2MeC_4^=$			.00541	.00541	.006	.00051	.00592	.007
C_6+	Trace		.41976	.41976	.48	.21658	.63634	.723
	100.00	87.143	.61713	87.7569	99.996	.21903	87.97597	100.001

C_4's

C_5's

Calculated Properties Hexanes Plus:

	Dry Ice Trap Liquid	Wet Ice Trap Liquid
Specific Gravity: 60/60	0.7439	0.7991
Molecular Weight:	96.23	134

AR3B-355-1

Table 2

AtlanticRichfieldCompany

Well Calculation Sheet – Short

Nº 86549

Title or object of calculations: Calculated Gas Compositions

Problem: | Field: | Well: | Date:

From to: Calculated by: started: finished:

References: (Based on Calculated Field Container-Liquid Quantity)

Equation:

Concurrent sheets:

Remarks:

Name	Dry Gas #2410		Dry Ice Trap Calc. Liquid Composition	Gas Composition from Wet Ice Trap		Wet Ice Trap Liquid, g moles	Total Gas Sample, g moles	Total Gas Sample Composition
Units	Mol%	g-Mols	g-Mols	g-Mols	Mol%	g moles	g moles	Mol%
H_2	4.42	3.851	.00001	3.85101	4.39	—	3.85101	4.375
O_2+Ar	0.93	.810	.0002	.81002	.92	—	.81002	.920
N_2	65.07	56.704	.00044	56.70444	64.57	—	56.70444	64.414
C_1	2.33	2.030	.00017	2.03017	2.31	—	2.03017	2.306
CO	2.01	1.752	.00002	1.75202	2.00	—	1.75202	1.990
CO_2	22.05	19.215	.02253	19.23753	21.91	—	19.23753	21.853
$C_2^=$	0.93	.810	.00122	.81122	.92	—	.81122	.922
C_2	0.95	.828	.00246	.83046	.95	.00002	.83048	.943
$C_3^=$	0.45	.392	.00479	.39679	.45	—	.39679	.451
C_3	0.47	.410	.00727	.41727	.48	.00014	.41741	.474
iC_4	0.06	.052	.01176	.05376	.06	.00001	.05377	.061
Butene-1	0.16	.139	.01328	.15228	.17	—	.15228	.173
NC_4	0.09	.078	.02371	.10171	.12	.00035	.10206	.116
Trans Butene-2	0.02	.017	.00261	.01961	.02	—	.01961	.022
Cis Butene-2	0.01	.009	.00598	.01498	.02	.00009	.01507	.017
$3MeC_4^=$	Trace	—	.00347	.00347	.004	.00004	.00351	.004
iC_5	0.01	.009	.01184	.02084	.02	.00011	.02095	.024
Pentene-1	0.02	.017	.00671	.02371	.03	—	.02371	.027
NC_5	0.02	.017	.06238	.07938	.09	.00071	.08009	.091
Trans Pentene-2			.00298	.00298	.003	.0016	.00314	.004
Cis Pentene-2			.00077	.00077	.001	.00031	.00108	.001
$2MeC_4^=$			.00336	.00336	.004	.00051	.00387	.004
C_{6+}	Trace		.49441	.49441	.56	.21658	.71099	.808
	100.00	87.143	.67217	87.81219	100.002	.21903	88.03122	100.000

Calculated Properties

Hexanes Plus:

	Dry Ice Trap	Wet Ice Trap Liquid
Specific Gravity 60/60	0.7439	0.7991
Molecular Weight	96.23	134

AR3B-355-1

WET ICE TRAP NAPHTHA

Run No. 1

Water Recovered 190.53 gm.

Oil Recovered 29.73 gm.

S.G. 60°/60°F 0.7991 (45.6° API)

Dry Ice Trap Gas Volume 73.91 SCF (Dry)

SIMULATED TBP DISTILLATION BY GC

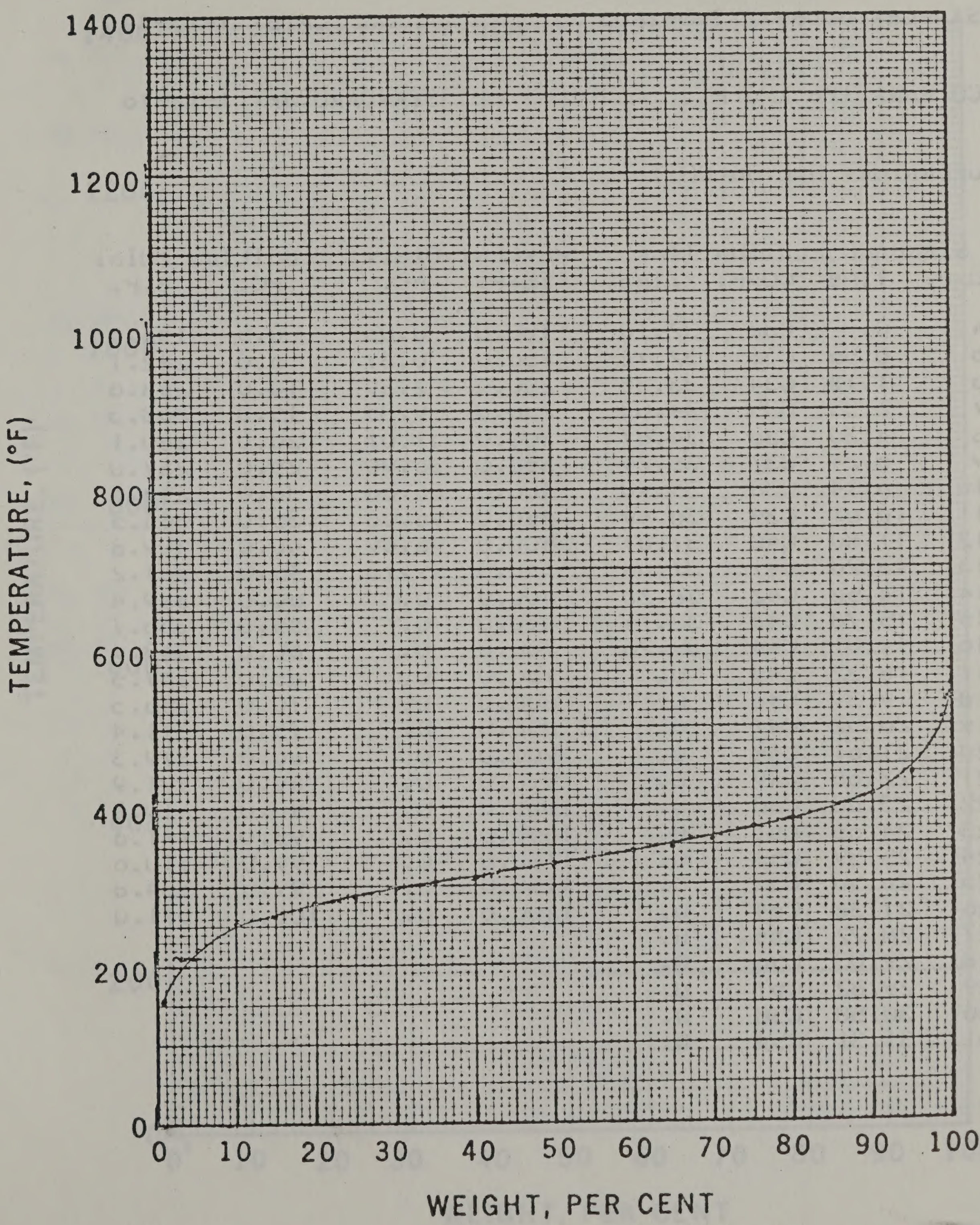
SAMPLE: NAPTHA - WET ICE TRAP— RUN 1

NBP:

COLUMN: # 2403

OPERATOR:

DATE: 1-15-76



FORM No. 70-A-6A

SIMULATED TBP DISTILLATION BY GC
WHOLE OIL

WET ICE TRAP NAPHTHA

SAMPLE: 605B-727390-2403 DATE: 1-15-76

COLUMN: 1/8 X 6 FT. STANDARD OF: 1-12-76

OPERATOR: H.E.SOLCOTT

STANDARD ELUTION TIME				PERCENT DIST.		BOILING POINT	
COMP.	TIME	COMP.	TIME	TEMP.	PC.	PC.	B.P.
C4	0.	C32	32.10	100.0	0.05	0.5	156.6
C5	0.55	C33	32.72	150.0	0.37	5.0	222.1
C6	1.18	C34	33.38	200.0	2.39	10.0	253.6
C7	2.55	C35	34.03	250.0	9.35	15.0	263.3
C8	4.30	C36	34.67	300.0	31.01	20.0	280.1
C9	6.24	C37	35.29	350.0	66.90	25.0	287.0
C10	8.14	C38	35.90	400.0	86.66	30.0	298.6
C11	10.01	C39	36.49	450.0	96.08	35.0	304.5
C12	11.80	C40	37.07	500.0	98.69	40.0	309.8
C13	13.20	C41	37.64	550.0	99.75	45.0	321.2
C14	14.58	C42	38.20	600.0	0.	50.0	329.4
C15	15.78	C43	38.75	650.0	0.	55.0	338.7
C16	17.01	C44	39.28	700.0	0.	60.0	343.7
C17	18.22	C45	0.	750.0	0.	65.0	347.5
C18	19.39	C46	0.	800.0	0.	70.0	356.5
C19	20.52	C47	0.	850.0	0.	75.0	371.4
C20	21.61	C48	0.	900.0	0.	80.0	379.3
C21	22.66	C49	0.	950.0	0.	85.0	391.9
C22	23.68	C50	0.	1000.0	0.	90.0	410.2
C23	24.65	C51	0.	1050.0	0.	95.0	441.6
C24	25.59	C52	0.	1100.0	0.	99.0	510.6
C25	26.50	C53	0.	1150.0	0.	99.5	534.8
C26	27.38	C54	0.	1200.0	0.	100.0	571.0
C27	28.22	C55	0.				
C28	29.03	C56	0.				
C29	29.82	C57	0.				
C30	30.58	C58	0.				
C31	31.31	C59	0.				

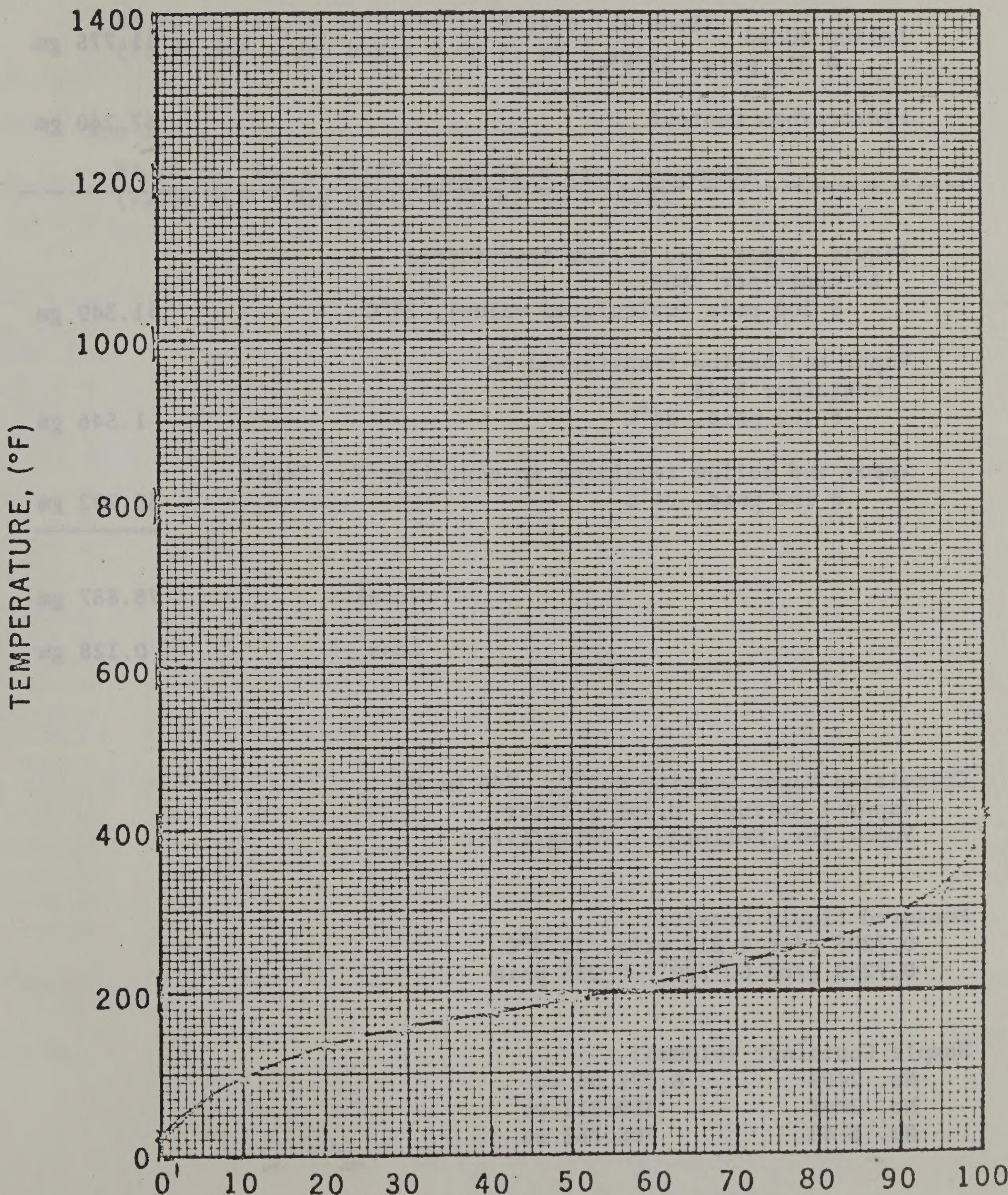
SIMULATED TBP DISTILLATION BY GC

SAMPLE: CONDENSATE SAMPLE WITHDRAWN FROM #2408 (DRY ICE TRAP) (B-48) NBP:

COLUMN: OPERATOR:

DATE:

Temperature: 24 °C



FORM No. 70-A-6A

Sample No. 605 B-727390-2408

Weight Balance

Total contents (liquid, vapor, helium) @ 212 psia, 23.5°C	79.015 gm
Helium added @ 212 psia, 23.5°C	11.775 gm
Hydrocarbon content	67.240 gm

Liquid, vapor, and helium transferred to container 2M68 @ 200 psia (calculated value), 24°C	41.349 gm
Vapor and helium transferred to container B-48 @ 192 psia, 24°C	1.546 gm
Vapor and helium remaining in container No. 2408 @ 192 psia, 24°C	35.992 gm
Total	78.887 gm
Loss	0.128 gm

Calculated Vapor Density @ 0°C, 760 mm Hg
Vapor + Helium: 0.357 g/liter
Vapor (ex. Helium): 1.761 g/liter

Measured Liquid Density:
0.7206 g/cc @ 215 psia, 21.4°C
0.7259 g/cc 60°/60°F @ 215 psia

Sample Container Volumes:

No. 2408	6,071.96 cc
No. 2M68	319.812 cc
No. B-48	305.762 cc

Sample No. 605 B-727390-2408

(Continued)

Gas flow from dry ice traps:

Run 1

88.40 cu. ft. @ 32°F and 11.8 psia (assumed)
(73.91 SCF - dry basis @ 60°F, 14.7 psia)

Run 2

87.12 cu. ft. @ 32/35°F and 11.8 psia (assumed)
(72.84 SCF - dry basis @ 60°F, 14.7 psia)

GAS CHROMATOGRAPHIC ANALYSIS

SAMPLE NUMBER 605B-727390-2408 DATE 12-24-75

	MOL. WT. PC. FOUND	NORMALIZED ~~HE FREE~~	~~HE,O2,N2,FREE~~	WEIGHT PC	DENSITY LB/CU.FT.
HE	89.37	786.71	88.72	44.38	0.009692
H2	0.56	4.93	0.56	0.14	0.000031
O2	0.07	0.62	0.07	0.28	0.000062
N2	5.03	44.28	4.99	17.46	0.003897
C1	0.16	1.41	0.16	0.32	0.000071
CO	0.17	1.50	0.17	0.59	0.000132
CO2	2.51	22.10	2.49	13.70	0.003054
C2-	0.12	1.06	0.12	0.42	0.000093
C2	0.15	1.32	0.15	0.56	0.000125
H2S	0.	0.	0.	0.	0.
C3-	0.15	1.32	0.15	0.78	0.000175
C3	0.15	1.32	0.15	0.82	0.000183
I-C4	0.03	0.26	0.03	0.22	0.000048
C4-	0.36	3.17	0.36	2.51	0.000558
N-C4	0.22	1.94	0.22	1.59	0.000354
C4-T	0.07	0.62	0.07	0.49	0.000109
C4-C	0.04	0.35	0.04	0.28	0.000062
C5-	0.02	0.18	0.02	0.17	0.000039
I-C5	0.07	0.62	0.07	0.63	0.000140
C5-	0.18	1.58	0.18	1.57	0.000349
N-C5	0.25	2.20	0.25	2.24	0.000499
C5-T	0.08	0.70	0.08	0.70	0.000155
C5-C	0.02	0.18	0.02	0.17	0.000039
C5-	0.09	0.79	0.09	0.78	0.000175
C6+	0.86	7.57	0.85	9.19	0.002049
TOTAL	100.73	886.71	100.00	100.00	0.022288

Mol. Wt. (ex He) =

1 g mol = 8.003 g

He = 88.72%

$(.8872)(4.003) + .1128x = 8.003$

$.1128x = 4.4515$

$x = \underline{39.464}$

SAMPLE NUMBER 605B-727390-2406

GAS CHROMATOGRAPHIC ANALYSIS

GAS DENSITY AT 32 F AND 14.696 PSIA, LB/CU.FT.	0.0223
GAS DENSITY AT 0 DEG. C AND 760 MM, G/L	0.3570
GAS SPECIFIC GRAVITY, AIR =1	0.2763
AVERAGE MOL WEIGHT OF GAS	8.003
AVERAGE MOL WEIGHT OF HYDROGEN IN GAS	0.313
AVERAGE MOL WEIGHT OF CARBON IN GAS	1.892
WEIGHT PERCENT TOTAL CARBON	23.65
WEIGHT PERCENT ORGANIC CARBON	19.65
WEIGHT PERCENT HYDROGEN	3.91
WEIGHT PERCENT C4+	20.31
SPECIFIC GRAVITY OF LIQUID C4+, 60/60 F	0.3862
DENSITY OF C4+ IN GAS,LBS/CU.FT. AT 32F, 14.696 PSIA	0.2017
DENSITY OF C3 MINUS, LBS/CU.FT. AT 32F, 14.696 PSIA	0.0181
DENSITY OF C3 MINUS, G/L, 0 DEG.C AND 760 MM	0.2904

ANALYST

CHECKED BY

GAS CHROMATOGRAPHIC ANALYSIS

SAMPLE NUMBER 005B-727390-2408 DATE 12-24-75

	MOL. WT. PC.FOUND	NORMALIZED HE FREE	NORMALIZED HE,O2,N2,FREE	WEIGHT PC	DENSITY LB/CU.FT.
HE	89.37	0.	0.	0.	0.
H2	0.56	4.93	4.93	0.25	0.000277
O2	0.07	0.62	0.62	0.50	0.000549
N2	5.03	44.28	44.28	31.44	0.034555
C1	0.16	1.41	1.41	0.57	0.000629
CO	0.17	1.50	1.50	1.06	0.001167
CO2	2.51	22.10	22.10	24.64	0.027083
C2-	0.12	1.06	1.06	0.75	0.000825
C2	0.15	1.32	1.32	1.01	0.001106
H2S	0.	0.	0.	0.	0.
C3-	0.15	1.32	1.32	1.41	0.001546
C3	0.15	1.32	1.32	1.48	0.001621
I-C4	0.03	0.26	0.26	0.39	0.000427
C4-	0.36	3.17	3.17	4.50	0.004952
N-C4	0.22	1.94	1.94	2.65	0.003135
C4-T	0.07	0.62	0.62	0.88	0.000963
C4-C	0.04	0.35	0.35	0.50	0.000550
C5-	0.02	0.18	0.18	0.31	0.000344
I-C5	0.07	0.62	0.62	1.13	0.001238
C5-	0.18	1.58	1.58	2.82	0.003095
N-C5	0.25	2.20	2.20	4.02	0.004422
C5-T	0.08	0.70	0.70	1.25	0.001376
C5-C	0.02	0.18	0.18	0.31	0.000344
C5-	0.09	0.79	0.79	1.41	0.001547
C6+	0.86	7.57	7.57	16.53	0.018169
TOTAL	100.73	100.00	100.00	100.00	0.109923

SAMPLE NUMBER 005B-727390-2406

GAS CHROMATOGRAPHIC ANALYSIS

GAS DENSITY AT 32 F AND 14.696 PSIA, LB/CU.FT.	0.1099
GAS DENSITY AT 0 DEG. C AND 760 MM, G/L	1.7608
GAS SPECIFIC GRAVITY, AIR =1	1.3625
AVERAGE MOL WEIGHT OF GAS	39.467
AVERAGE MOL WEIGHT OF HYDROGEN IN GAS	2.776
AVERAGE MOL WEIGHT OF CARBON IN GAS	16.779
WEIGHT PERCENT TOTAL CARBON	42.51
WEIGHT PERCENT ORGANIC CARBON	35.34
WEIGHT PERCENT HYDROGEN	7.03
WEIGHT PERCENT C4+	36.51
SPECIFIC GRAVITY OF LIQUID C4+, 60/60 F	0.3862
DENSITY OF C4+ IN GAS,LBS/CU.FT. AT 32F, 14.696 PSIA	0.2017
DENSITY OF C3 MINUS, LBS/CU.FT. AT 32F, 14.696 PSIA	0.0869
DENSITY OF C3 MINUS, G/L, 0 DEG.C AND 760 MM	1.3916

ANALYST

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GAS CHROMATOGRAPHIC ANALYSIS

SAMPLE NUMBER 0056-727390-2410 DATE 12-19-75

	MOL. WT. PC. FOUND	NORMALIZED HE FREE	~~HE,O2,N2,FREE~~	WEIGHT PC	DENSITY LB/CU.FT.
HE	2.69	0.	0.	0.	0.
H2	4.30	4.42	4.42	0.29	0.000246
O2	0.90	0.93	0.93	0.97	0.000825
N2	63.28	65.06	65.06	59.90	0.050775
C1	2.27	2.33	2.33	1.23	0.001043
CO	1.95	2.00	2.00	1.85	0.001564
CO2	21.45	22.05	22.05	31.89	0.027033
C2-	0.90	0.93	0.93	0.85	0.000723
C2	0.92	0.95	0.95	0.93	0.000792
H2S	0.	0.	0.	0.	0.
C3-	0.44	0.45	0.45	0.63	0.000530
C3	0.46	0.47	0.47	0.69	0.000581
I-C4	0.06	0.06	0.06	0.12	0.000100
C4-	0.16	0.16	0.16	0.30	0.000257
N-C4	0.09	0.09	0.09	0.18	0.000150
C4-T	0.02	0.02	0.02	0.04	0.000032
C4-C	0.01	0.01	0.01	0.02	0.000016
C5-	0.	0.	0.	0.	0.
I-C5	0.01	0.01	0.01	0.02	0.000021
C5-	0.02	0.02	0.02	0.05	0:000040
N-C5	0.02	0.02	0.02	0.05	0.000041
C5-T	0.	0.	0.	0.	0.
C5-C	0.	0.	0.	0.	0.
C5-	0.	0.	0.	0.	0.
C6+	0.	0.	0.	0.	0.
TOTAL	99.95	100.00	100.00	100.00	0.084772

SAMPLE NUMBER 005B-727390-2410

GAS CHROMATOGRAPHIC ANALYSIS

GAS DENSITY AT 32 F AND 14.696 PSIA, LB/CU.FT.	0.0848
GAS DENSITY AT 0 DEG. C AND 760 MM, G/L	1.3579
GAS SPECIFIC GRAVITY, AIR =1	1.0508
AVERAGE MOL WEIGHT OF GAS	30.437
AVERAGE MOL WEIGHT OF HYDROGEN IN GAS	0.380
AVERAGE MOL WEIGHT OF CARBON IN GAS	4.152
WEIGHT PERCENT TOTAL CARBON	13.64
WEIGHT PERCENT ORGANIC CARBON	4.15
WEIGHT PERCENT HYDROGEN	1.25
WEIGHT PERCENT C4+	0.00
SPECIFIC GRAVITY OF LIQUID C4+, 60/60 F	0.5030
DENSITY OF C4+ IN GAS,LBS/CU.FT. AT 32F, 14.696 PSIA	0.1642
DENSITY OF C3 MINUS, LBS/CU.FT. AT 32F, 14.696 PSIA	0.0845
DENSITY OF C3 MINUS, G/L, 0 DEG.C AND 760 MM	1.3528

ANALYST

CHECKED BY

CHROMATOGRAPH ANALYSIS

Type of Sample: Paraho Project - 25A Run SW20

Method: —

Date Run: December 5, 1975

Sample Cyl. No.: —

Component	Run #1 (12/5/75) Mol %	Run #1 (12/5/75) Normalized Less	Run #2 (12/8/75) Mol %	Run #2 (12/8/75) Normalized Less
He	-	-	-	-
H_2	3.62	3.60	3.64	3.63
O_2 + AR	0.91	0.91	0.94	0.94
N_2	64.56	64.27	64.47	64.36
C_1	2.29	2.28	2.28	2.28
CO	2.41	2.40	2.45	2.45
CO_2	23.06	22.96	23.07	23.03
C_2-	0.92	0.92	0.92	0.92
C_2	0.87	0.87	0.85	0.85
H_2S	0.10	0.10	Trace	Trace
C_3-	0.44	0.44	0.43	0.43
C_3	0.39	0.39	0.27	0.27
IC_4	0.06	0.06	0.10	0.10
Iso Butylene Butene-1	0.19	0.19	0.18	0.18
NC_4	0.10	0.10	0.09	0.09
Trans Butene-2	0.02	0.02	0.01	0.01
CIS Butene-2	0.01	0.01	0.01	0.01
3 Methylbutene	Trace	Trace	Trace	Trace
IC_5	0.01	0.01	0.01	0.01
Pentene-1	0.03	0.03	0.04	0.04
NC_5 2-Methylbutene-1	0.04	0.04	0.05	0.05
Trans Pentene-2	Trace	Trace	Trace	Trace
CIS Pentene-2	Trace	Trace	Trace	Trace
2 Methylbutene-2	Trace	Trace	0.01	0.01
C_6+	0.40	0.40	0.34	0.34
	100.43	100.00 mol %	100.16	100.00

CHROMATOGRAPH ANALYSIS

Type of Sample: Paraho Project

Method:

Date Run: December 24, 1975

Sample Cyl. No.: —

Component	605B - 727390-2402 Mol %	605B - 727390-2402 Normalized Less	605B -727290-2408 Mol %	605B -727290-2408 Normalized Less
He	93.08	Helium	89.37	Helium
H_2	0.19	2.44	0.56	4.93
O_2 + AR	0.92	11.79	0.07	0.62
N_2	4.83	61.94	5.03	44.27
C_1	0.04	0.51	0.16	1.41
CO	0.03	0.38	0.17	1.50
CO_2	0.53	6.79	2.51	22.09
C_2-	0.60	7.69	0.12	1.06
C_2	0.04	0.51	0.15	1.32
H_2S	-	-	-	-
C_3-	0.02	0.26	0.15	1.32
C_3	0.02	0.26	0.15	1.32
IC_4	Trace	Trace	0.03	0.26
Iso Butylene Butene-1	0.06	0.77	0.36	3.17
NC_4	0.04	0.51	0.22	1.94
Trans Butene-2	0.01	0.13	0.07	0.62
CIS Butene-2	0.01	0.13	0.04	0.35
3 Methylbutene	Trace	Trace	0.02	0.18
IC_5	0.01	0.13	0.07	0.62
Pentene-1	0.03	0.38	0.18	1.58
NC_5 2-Methylbutene-1	0.04	0.51	0.25	2.20
Trans Pentene-2	Trace	Trace	0.08	0.70
CIS Pentene-2	Trace	Trace	0.02	0.18
2 Methylbutene-2	0.01	0.13	0.09	0.79
C_6+	0.37	4.74	0.86	7.57
	100.88	100.00	100.73	100.00

CHROMATOGRAPH ANALYSIS

Type of Sample: Paraho Gas

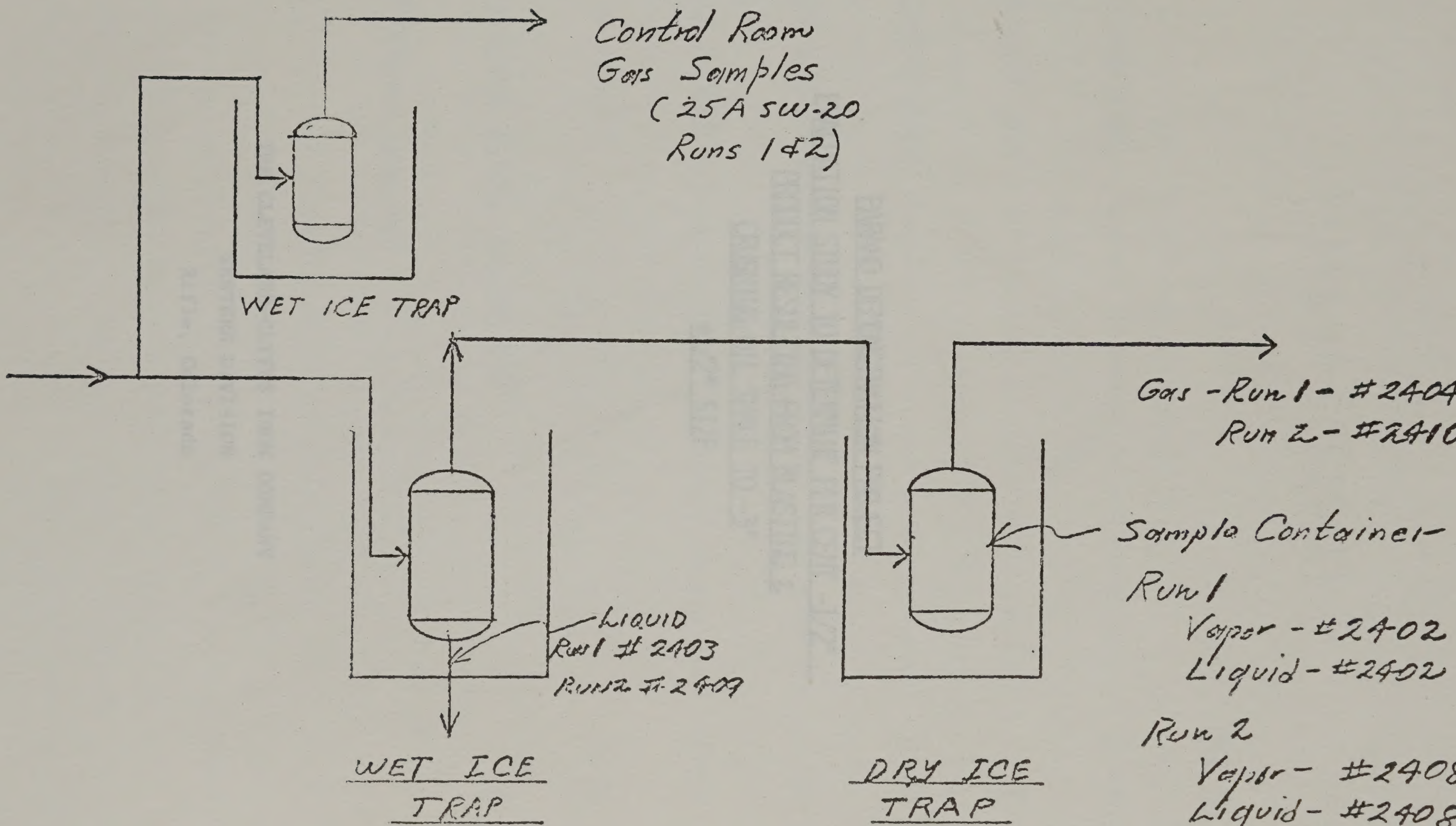
Date Run: December 19, 1975

Method: —

Sample Cyl. No.: —

Component	605B - 727390-2404 Mol %	605B - 727390-2404 Normalized Less Helium	605B - 727390-2410 Mol %	605B - 727390-2410 Normalized Less Helium
He	18.12		2.69	
H_2	3.29	4.00	4.30	4.42
O_2 + AR	1.34	1.63	0.90	0.93
N_2	53.84	65.41	63.28	65.07
C_1	1.70	2.06	2.27	2.33
CO	1.62	1.97	1.95	2.01
CO_2	18.22	22.13	21.45	22.05
C_2-	0.76	0.92	0.90	0.93
C_2	0.68	0.83	0.92	0.95
H_2S	-	-	-	-
C_3-	0.34	0.41	0.44	0.45
C_3	0.33	0.40	0.46	0.47
IC_4	0.06	0.07	0.06	0.06
Iso Butylene Butene-1	0.08	0.10	0.16	0.16
NC_4	0.04	0.05	0.09	0.09
Trans Butene-2	Trace	Trace	0.02	0.02
CIS Butene-2	Trace	Trace	0.01	0.01
3 Methylbutene	Trace	Trace	Trace	Trace
IC_5	Trace	Trace	0.01	0.01
Pentene-1	0.01	0.01	0.02	0.02
NC_5 2-Methylbutene-1	0.01	0.01	0.02	0.02
Trans Pentene-2				
CIS Pentene-2				
2 Methylbutene-2				
C_6+	Trace	Trace	Trace	Trace
	100.44	100.00	99.95	100.00

RUN SW-20
SAMPLE IDENTIFICATION



PARAHO DEMONSTRATION PROJECT
EVALUATION STUDY TO DETERMINE PER CENT -1/2" PRODUCT RESULTING FROM BLASTING & CRUSHING OIL SHALE TO -3" +1/2" SIZE

THE CLEVELAND-CLIFFS IRON COMPANY
WESTERN DIVISION
Rifle, Colorado

TABLE OF CONTENTS

EVALUATION STUDY TO DETERMINE PER CENT OF -1/2" PRODUCT RESULTING FROM BLASTING AND CRUSHING OIL SHALE TO -3" +1/2" SIZE

To prepare the product for this study, a 55' wide, 40' high, 21-1/2' deep round was blasted at the Anvil Points mine using a 23 hole double V cut drill pattern. The holes drilled were 4-1/4" in diameter and were loaded with 1,900 pounds of ammonium nitrate explosives as the primary blasting agent. The round produced approximately 3,100 tons of oil shale with a powder factor of .61 pounds of explosives per ton of product. From the blasted round approximately 500 tons of representative product were separated and stored at the mine, the balance was trucked to the crushing plant for retorting. The approximate 500 tons at the mine were further separated and 98.83 tons were loaded and trucked to the housing area for screening and sizing.

The sizing and weighing of the 98.83 tons of oil shale were done at the housing area with a fixed grizzly fabricated at the Paraho shops. A 12" opening between parallel grizzly rails was used to screen out the +12" product, a 6" opening between parallel grizzly rails was used to screen out the -12" +6" product and a 3" opening between parallel grizzly rails was used to screen out the -6" +3" product and the final -3" product. In conjunction with screening of the mine blast -3" product further hand sorting was required of product sizes larger than 3" in one dimension passing through the parallel grizzly rails with the oversize material going in with the -6" +3" product. Subsequent screening of all products was done over vibrating screens with 6", 3", 1-1/2" and 1/2" square openings.

The +12" product from the commercial blast was loaded and shipped to the Harry T. Campbell & Sons crushing and screening plant in Cockeysville, Maryland, where primary and secondary crushing tests and screening tests were conducted using commercial size equipment similar to that envisioned for future oil shale crushing and screening plants. The tertiary crushing test of the -6" +3" product and the screen sizing of the -3" product was done at the Paraho crushing and screening plant. Due to the difficulty in screening the -6" product to -3" over the fixed grizzly the product was halved and 8.6 tons were screened off for this test.

The primary and secondary crushing tests conducted at Harry T. Campbell's crushing and screening plant were made using a 36" x 60" McLanahan Rockmaster toothed single roll crusher. For the primary crushing tests the crusher opening was set at 6-1/2" and for the secondary crushing test the crusher opening was set at 3-1/2". This crusher was powered by a 440 volt, 200 H.P., 585 rpm Continental motor with a roll speed of 27 rpm and a tip speed of 310 fpm. A recording ammeter was used on both tests and power consumption for primary crushing calculated out to .21 KW per ton at a feed rate of 628 tons per hour. Power consumption for secondary crushing calculated out to .63 KW per ton at a feed rate of 314 tons per hour. From visual observation the 36" x 60" toothed single roll crusher handled the throughput of both the primary and secondary oil shale feed without any difficulty. The Paraho crushing and screening plant was used for both tertiary crushing and screening of the -3" product.

Ro-Tap tests, to determine per cent of -1/2" +3 mesh, -3 mesh +6 mesh, -6 mesh +10 mesh, -10 mesh +28 mesh, -28 mesh +60 mesh, -60 mesh +200 mesh and -200 mesh fines, were conducted at the Paraho laboratory.

These tests were made from samples weighing approximately 60 pounds each of the -1/2" mine blast, primary crushed, secondary crushed, tertiary crushed and -3" products. These results are reported in Table I.

To obtain these samples the grab sampling technique was used and representative samples were taken of the -1/2" mine blast, primary crushed, secondary crushed and -3" products at two foot intervals with a laboratory hand scoop. These samples were placed in five gallon sample pails with proper covers for transportation to the Paraho laboratory.

Included is a table, graphs, flow sheet, views and inserts showing product sizing, mine blast drill pattern and crushing equipment drawings.

Page 5, Table I shows the size consist of the mine blast product, primary crushed product, secondary crushed product, tertiary crushed product and the final -3" product.

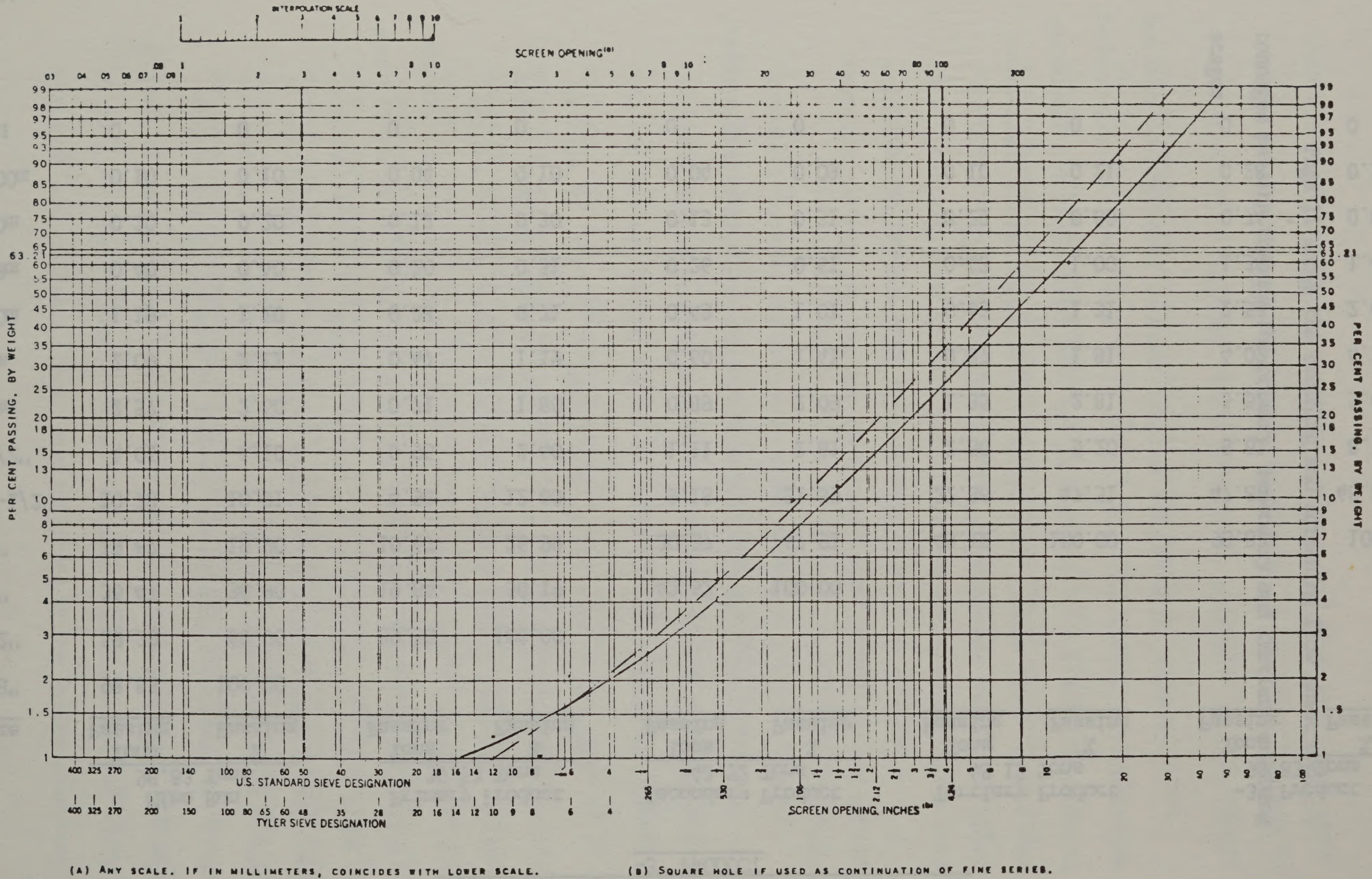
Pages 6, 7, 8, 9 and 10 show Graphs I, II, III, IV and V of resultant size distribution of the mine blast product, primary crushed product, secondary crushed product, tertiary crushed product and the final -3" product. The dashed line in Graph I shows the size distribution of mine blast oil shale from a test conducted by the U. S. Bureau of Mines at Anvil Points as reported by Mr. Matzack on page 20 in the Synthetic Fuels Data Handbook prepared by Cameron Engineers. The dashed line in Graph V shows the screen analysis of Paraho retort product showing the cutoff for usable oil shale retort product at 8 mesh. By calculation from this Graph the per cent waste -1/2" product for retorting is reduced from 8.7% to 5%.

Page 11 shows the crushing and screening flow sheet and tonnages passing through the primary, secondary and tertiary crushing stages.

SIZE SEPARATION OF MINE RUN PRODUCT, PRIMARY, SECONDARY, TERTIARY CRUSHED PRODUCT, AND FINAL -3" PRODUCT

	Mine Run 98.83 Tons		Primary Product 39.53 Tons		Secondary Product 42.52 Tons		Tertiary Product 48.12 Tons		-3" Product 98.83 Tons	
Size	Tons Passing	% Passing	Tons Passing	% Passing	Tons Passing	% Passing	Tons Passing	% Passing	Tons Passing	% Passing
+48"	98.83	100.00								
+12"	59.30	60.00	39.53	100.00						
+6"	36.47	36.90	19.84	50.19	42.52	100.00				
+3"	19.67	19.90	10.67	26.99	20.37	47.91	48.12	100.00	98.83	100
+1-1/2"	10.78	10.91	4.98	12.60	9.18	21.59	22.86	47.51	47.80	48.8
+1/2"	4.05	4.10	0.95	2.40	1.11	2.61	2.50	5.20	8.61	8.7
+3m	2.57	2.60	0.71	1.80	0.89	2.09	1.35	2.81	5.52	5.6
+6m	2.09	2.11	0.47	1.19	0.60	1.41	0.87	1.81	4.02	4.1
+10m	1.19	1.20	0.28	0.71	0.43	1.01	0.63	1.31	2.53	2.6
+28m	0.40	0.40	0.20	0.51	0.26	0.61	0.48	1.00	1.34	1.4
+60m	0.20	0.20	0.12	0.30	0.13	0.31	0.29	0.60	0.74	0.8
+200m	0.10	0.10	0.04	0.10	0.04	0.09	0.10	0.21	0.28	0.3
PAN	0	0	0	0	0	0	0	0	0	0

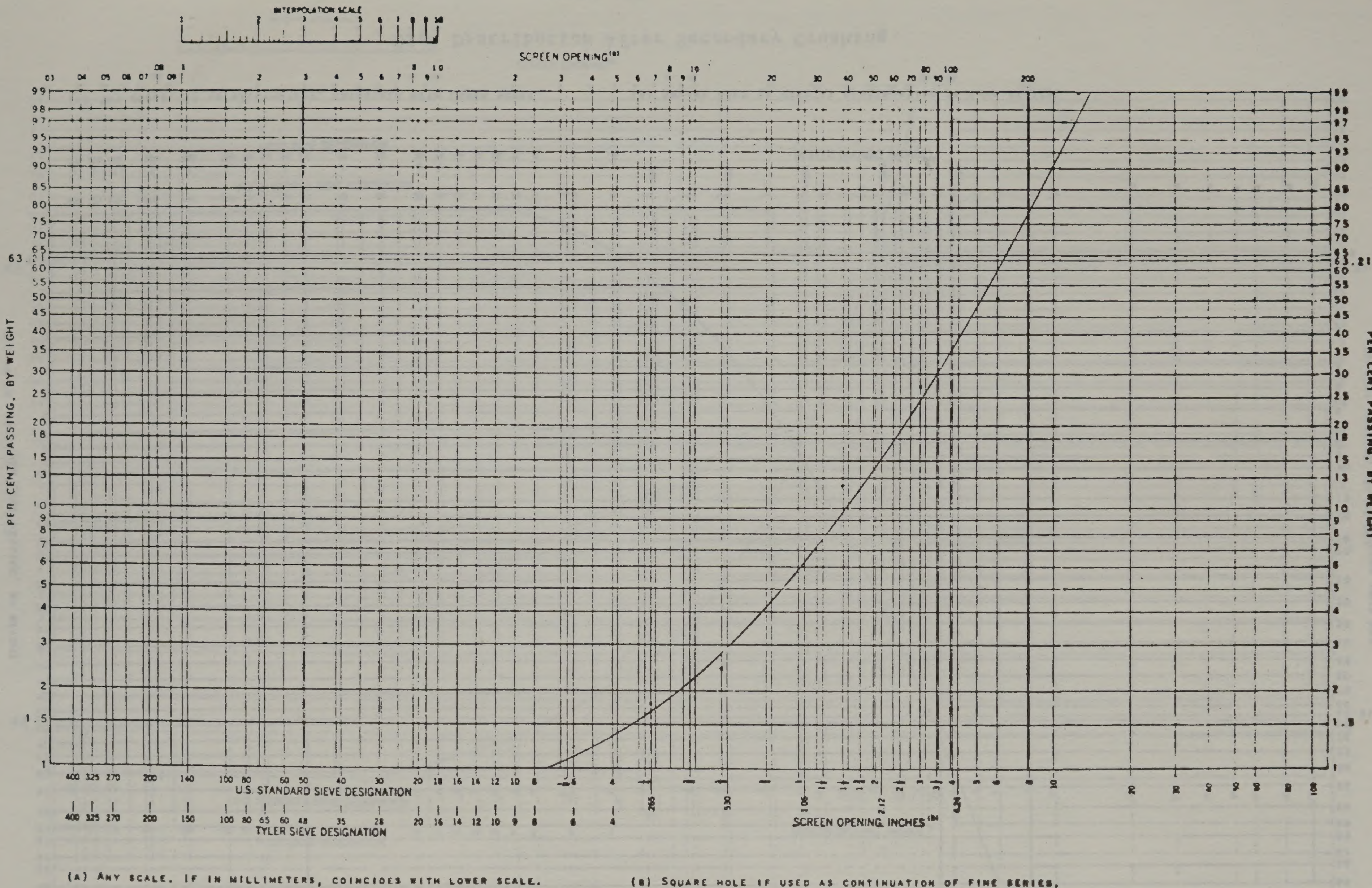
HLH/vc
3/23/76



Size Distribution After Mine Blast

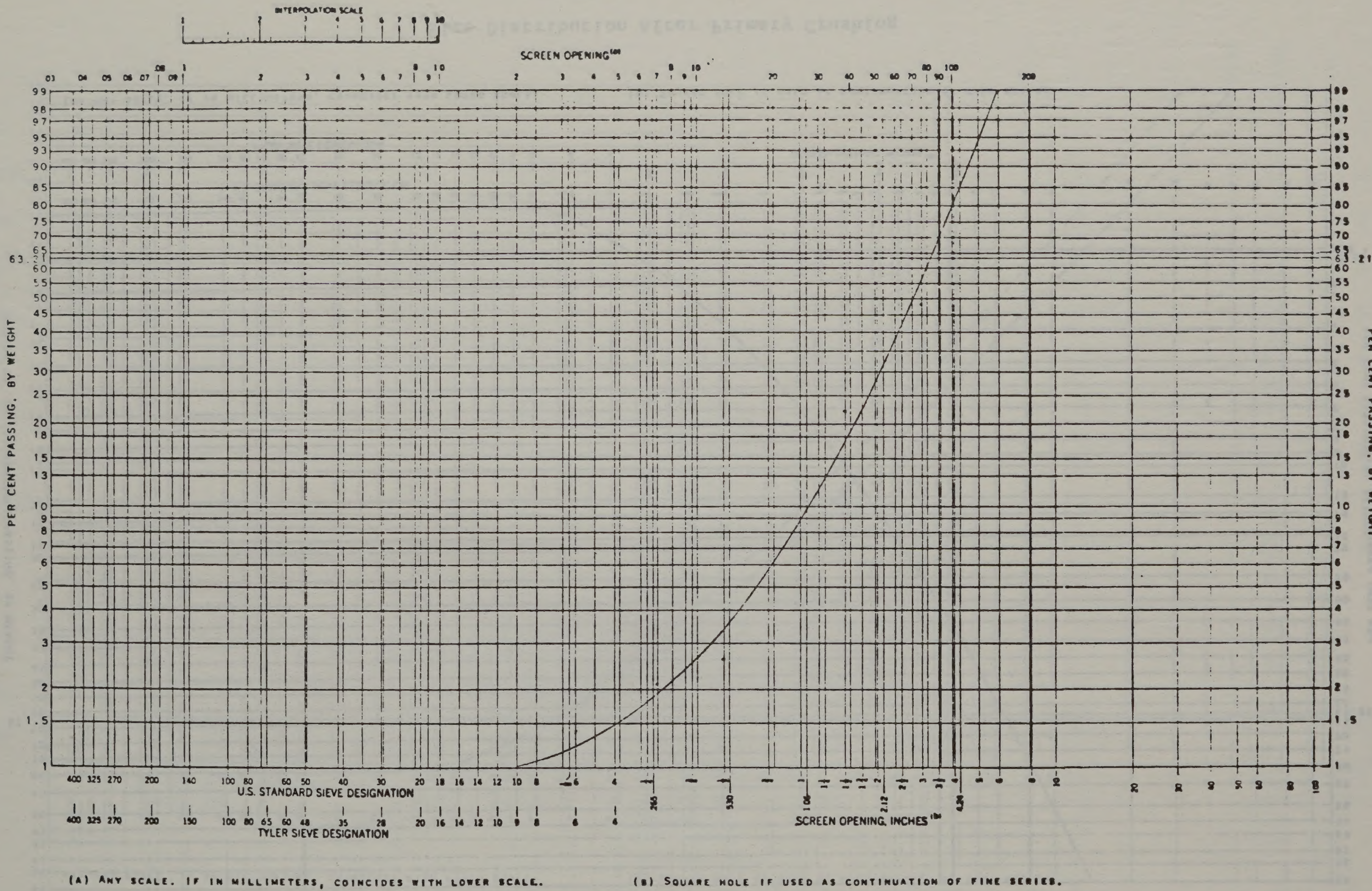
Cameron — — — CCIC ————

GRAPH I



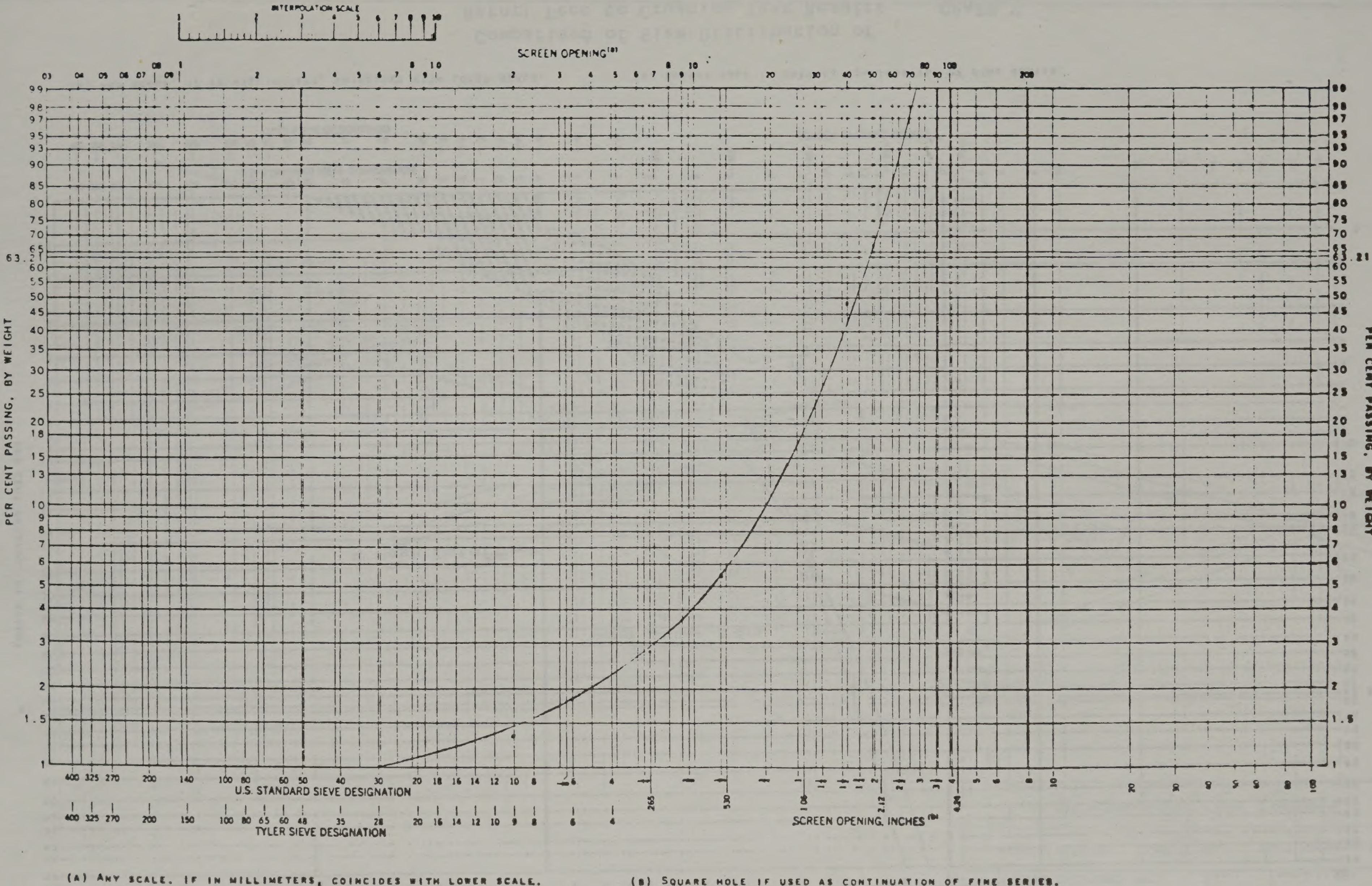
Size Distribution After Primary Crushing

GRAPH II



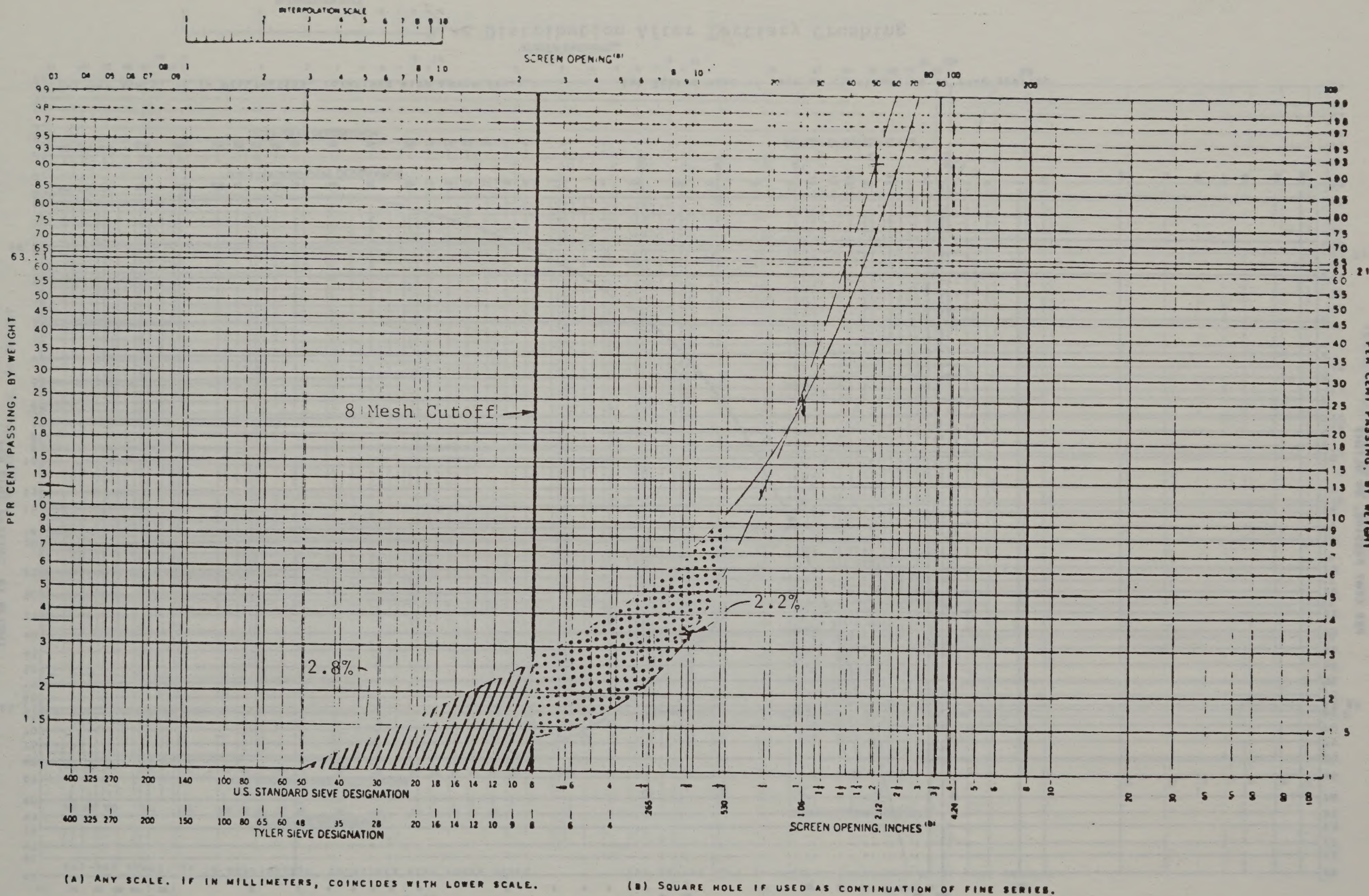
Size Distribution After Secondary Crushing

GRAPH III



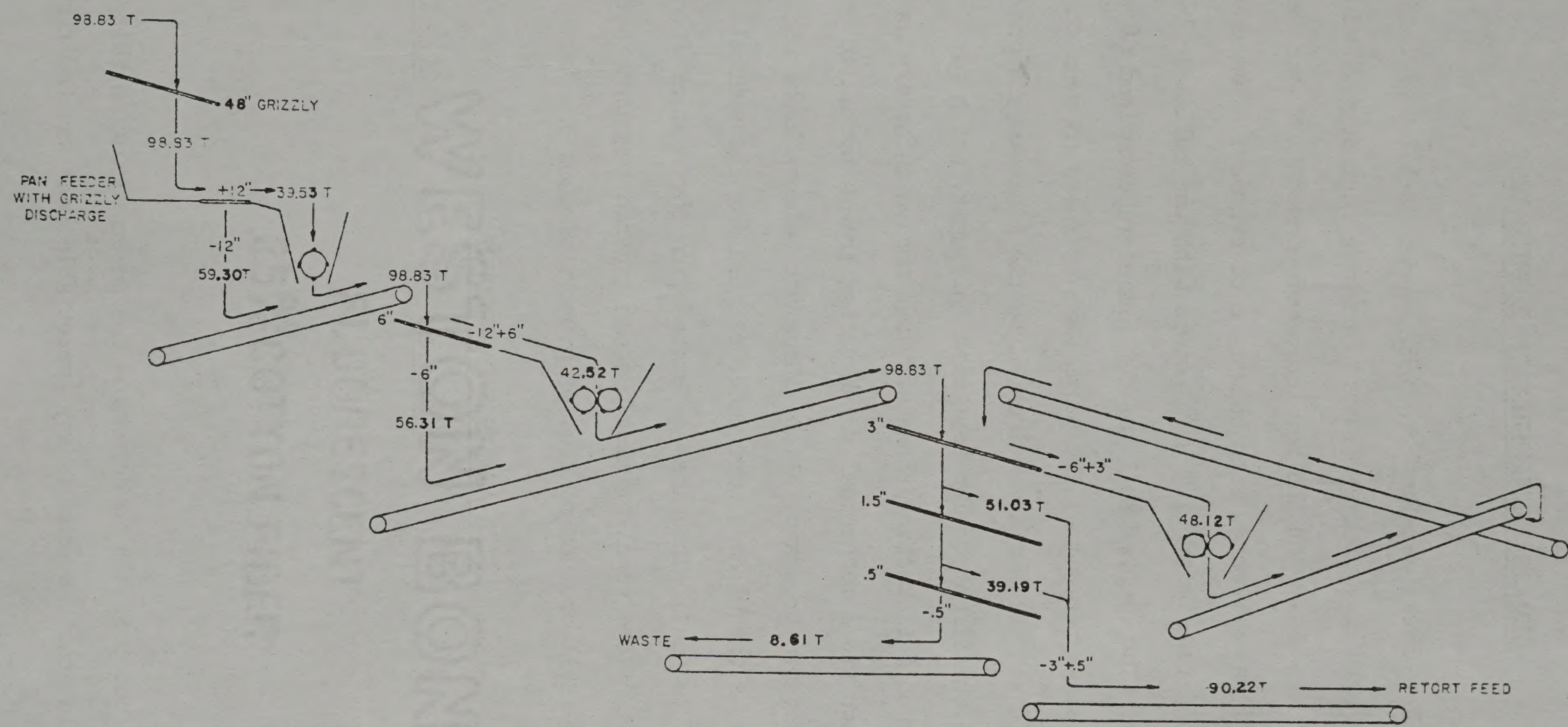
Size Distribution After Tertiary Crushing

GRAPH IV



Comparison of Size Distribution of
Retort Feed to Crushing Test Results GRAPH V

Crushing Test ———
Retort Feed — — —



The Cleveland-Cliffs Iron Company

WESTERN DIVISION		RIFLE, COLORADO 81650
FLOWSHEET — CRUSHING AND SCREENING OF OIL SHALE TO -3"+.5"	SCALE	DRAWN BY Hoe
		REVISED
DATE 3-3-76	APPROVED BY	DRAWING NUMBER

STAMLER FEEDER BREAKER CRUSHING TEST

A Stamler feeder breaker S/N 10932, Model BB-14B-8 mechanical type machine was used to conduct a primary crushing test of +12" mined product at Paraho to determine the per ton power consumption and the amount of -1/2" fines generated with this type of crusher. The conveyor and breaker were driven by two 100 H.P. motors with the relief in both using shear pins. The breaker roll was 34" diameter, comprised of six discs with four picks per disc. The picks were spiraled to even the load on the shaft and the shaft was located so the picks were approximately 4" above the flights. The test with this unit, which was originally designed for crushing trona ore, was not satisfactory as the feeder breaker was a mechanical drive rather than a hydraulic drive resulting in shear pin breakage. Also, three bit holders broke off during this test as the holders were underdesigned for the special breaker used in the test. The fines generated from the Stamler feeder breaker were 7.2% of the total primary product crushed compared to the McLanahan toothed roll crusher of 2.4% of primary product crushed.

SIZE ANALYSIS OF PRODUCT

Screen Size	% Passing	21.1 Tons
+12"	100%	
6"	48.8%	
3"	24.3%	
1/2"	7.2%	

It was not possible to determine the power factor on this test as the motor would stall as soon as any appreciable load was fed through the feeder breaker.